EASTERN RESEARCH GROUP, INC.

MEMORANDUM

TO: Fred Porter, U.S. Environmental Protection Agency

FROM: Christy Burlew and Ruth Mead, Eastern Research Group, Inc.

DATE: November 30, 1998

SUBJECT: Final Minutes of September 16 and 17, 1998 Industrial Combustion Coordinated Rulemaking Coordinating Committee Meeting

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1.0 INTRODUCTION

- The eleventh and final meeting of the Coordinating Committee (CC) for the Industrial Combustion Coordinated Rulemaking (ICCR) project was held on September 16 and 17, 1998, in Durham, North Carolina. A list of attendees is included as Attachment 1.

- A meeting agenda outlining the topics of discussion is included as Attachment 2.

- The purposes of the meeting were to:

  1. Be informed about Work Group (WG) decisions/closure and formulate recommendations to EPA, if appropriate, for the following:

     - Incinerator WG - Regulatory Alternatives Paper
     - Boiler WG - MACT Floor for Natural Gas and Oil
     - Boiler WG - Hazardous Air Pollutants (HAPs) of Interest for Fossil Fuel
     - Turbine WG - Cost Effectiveness of Emission Control
     - Testing and Monitoring Protocol WG - Interpreting Non-Detect Emission Measurements
     - Engine WG - Rich Burn Engine Definition
     - Engine WG - Assessment of Emission Database
     - Engine WG - MACT for Digester and Landfill Gas Combustion

  2. Be informed about WG works-in-progress and data/information items and forward these to EPA for its consideration.

- The “flash minutes” of the meeting, which list key decisions and action items, are included as Attachment 3.

2.0 SUMMARY OF DISCUSSION

Fred Porter of EPA opened the meeting. The meeting discussion generally followed the agenda. Topics of discussion are summarized in the following sections:

2.1 General Business and EPA Feedback

2.2 Incinerator Work Group Closure Presentation on Regulatory Alternatives Paper and CC Recommendation

2.3 Boiler Work Group Closure Presentation on Preliminary MACT Floor for Natural Gas and Fuel Oil-Fired Boilers and CC Recommendation

2.4 Boiler Work Group Closure Presentation on HAPs of Interest for Fossil Fuel-Fired Boilers and CC Recommendation

2.5 Turbine Work Group Closure Presentation on Cost of HAP Emission Control and CC Recommendation

2.6 Testing and Monitoring Protocol Work Group Closure Presentation on Using Emissions Databases Containing Non-Detection Values and CC Recommendation

2.7 Engine Work Group Closure Presentation on Rich Burn Engine Definition and CC Recommendation

2.8 Engine Work Group Closure Presentation on Assessment of Emission Database and CC Recommendation

2.9 Engine Work Group Closure Presentation on Above-the-Floor MACT Options for Digester and Landfill Gas Combustion and CC Recommendation

2.10 Works-in-Progress and Data/Information Items

2.11 Environmental Caucus Work-in-Progress on Environmental Justice

2.1 GENERAL BUSINESS AND EPA FEEDBACK

- Relative to the previous recommendations from the CC for testing boilers and incinerators, Fred Porter of EPA indicated that the Agency is still considering those requests, they are beginning to look at potential sites, but no definite plans have been made.

- Mr. Porter indicated that the Agency thinks the recommendations forwarded by the CC on subcategories and MACT floors for reciprocating internal combustion engines (RICE) have merit. Pending further information, EPA will be proceeding with the rulemaking using these recommendations.

- There was a question at the July CC meeting regarding a reference to an EPA implementation plan on Environmental Justice (EJ). Fred Porter and EPA staff have been unable to locate this reference and therefore, the reference listed in the Incinerator Regulatory Alternatives Paper (RAP) has been deleted.

- Regarding the definition of non-hazardous solid waste for purposes of Section 129, Mr. Porter indicated that EPA is still working on this. EPA staff's feeling is that they will recommend that fuels, biomass, and other materials that seem more fuel-like than waste-like would be excluded from the solid waste definition. Currently, no criteria for determining whether a material is fuel-like have been developed, and Mr. Porter did not know if any such criteria would be similar to or different from the comparable fuel criteria in the hazardous waste rule. EPA staff are building on the CC recommendations and the draft solid waste definition that was previously released to the ICCR.

- A CC member asked if there would be opportunity to comment on the definition of non-hazardous solid waste that will be developed by EPA. Fred Porter indicated that there will be an opportunity for public comment on this issue when the ICCR rules are proposed, but EPA is not sure if it will propose the definition of non-hazardous solid waste separately.

2.2 INCINERATOR WORK GROUP CLOSURE PRESENTATION ON REGULATORY ALTERNATIVES PAPER AND CC RECOMMENDATION

- The Incinerator Work Group (IWG) presented the regulatory alternatives paper (RAP), which is the final consensus work product of the WG. The RAP documents the work done by the IWG to date. The final version of the RAP is provided as Attachment 4.

- The IWG indicated that there are areas of the RAP that need further development and analyses. The WG did not examine possible further subcategorization or combining of subcategories. For example, a WG member noted that the three size subcategories examined for the pathological incinerators subcategory may make sense for other subcategories. Further consolidation of subcategories may also be possible. The IWG also never examined the achievability of emission floors.

- The RAP contains information on five incinerator subcategories and two potential Section 129 boiler subcategories. Based on the information reviewed to date, the IWG has concluded that some of its five current subcategories have no MACT floor. It appears that the drum reclaimer subcategory might have a MACT floor because of the large number of these sources that have thermal oxidizers. There are also many controls listed in the inventory database for the miscellaneous industrial incinerator subcategory, which might indicate this subcategory has a potential MACT floor.

- Since the last version of the RAP was presented at the July CC meeting, the document has been updated to provide more data including growth projections, incorporate comments from the Boiler WG, expand subcategory definitions, and make editorial changes. A member of the IWG indicated that there were a few minor editorial comments at the last IWG meeting that the WG hoped could be included in the version of the RAP forwarded to EPA. These editorial comments affected three pages and are incorporated in Attachment 4.

- The IWG considers that the information presented in the RAP is representative of the incinerator subcategories and is good background for regulatory development. The WG requested that this final version of the RAP be forwarded to EPA.

- There was opportunity for public comment on the RAP. There were no comments from the public on this topic.

- Decision: The CC reached consensus to forward the Section 129 RAP to EPA as a CC recommendation.

2.3 BOILER WORK GROUP CLOSURE PRESENTATION ON PRELIMINARY MACT FLOOR FOR NATURAL GAS AND FUEL OIL-FIRED BOILERS AND CC RECOMMENDATION

- The Boiler WG gave a closure presentation on preliminary MACT floors for natural gas and fuel oil. The presentation and rationale document are provided as Attachments 5 and 6, respectively.

- The presentation discussed the preliminary subcategory and MACT floor analyses performed by the WG and the findings. The rationale paper contains details on the methodology and findings, and identifies and discusses issues where the WG did not reach consensus.

- The Boiler WG reviewed some editorial changes to the rationale document agreed upon by the WG the previous day. The title will be changed to make "Preliminary" the first word. The word "preliminary" will be added before "subcategories" and "MACT floors" in the last paragraph of the first section of the rationale document. Also, in Section 5.0 of the rationale document, the words "By consensus" will be deleted from the first sentence of that section. Finally, in Section 3.2.3.3, bullet #3, the WG changed "17" to "15" fuel oil-fired boilers to correctly reflect the data. These changes have been made in Attachment 6.

- A CC member representing State/local agencies commented that the presentation was inconsistent with the rationale document. The presentation should indicate that no MACT floor could be established on the basis of controls or emission limits, but that further investigation is needed of whether a MACT floor can be determined on the basis of GCP requirements. This issue is discussed in sections 3.4 through 3.6 of the report.

- A public commentor, Craig Harris, representing the Utility Air Regulatory Group, asked if there is a definition of the size of ICCR boilers because he assumes that utility boilers are not included. A member of the Boiler WG responded that there is no size definition but that utilities are not included in the ICCR and are defined elsewhere.

- A public commentor, David Marrack, a member of the Boiler and Incinerator WG's, pointed out that the available emissions data are very limited and the large variation in emissions within the boiler subcategories can not be explained. He suggested that an attempt should be made to further define the emissions from different subcategories of sources.

- Decision: The CC reached consensus to forward the report on preliminary MACT floor determinations for natural gas and fuel oil-fired boilers to EPA as a CC recommendation. The five wording changes suggested by the Boiler WG will be made to the document.

2.4 BOILER WORK GROUP CLOSURE PRESENTATION ON HAPS OF INTEREST FOR FOSSIL FUEL-FIRED BOILERS AND CC RECOMMENDATION

- The Boiler WG presented a closure presentation on HAPs of interest for fossil fuels, including gas, oil and coal. The presentation and rationale document are provided as Attachments 7 and 8, respectively.

- The purpose of the HAPs of interest lists are to narrow down the list of 188 HAPs to the pollutants that would require additional review and possible regulation for ICCR sources. The HAPs of interest lists presented in this document represent further investigation and compromise between the majority and minority reports that the Boiler WG presented at the February 1998 CC meeting.

- The WG reviewed the selection process used to develop the lists of HAPs of interest. The HAPs of interest list for gas includes 15 pollutants. The list for distillate oil contains 17 HAPs, the residual oil list has 18 HAPs and the list for coal has 34 HAPs. The WG clarified that in these lists polycyclic organic matter (POM) was meant to include the 16 polynuclear aromatic hydrocarbons (PAHs). The rationale document details the reasoning for listing each pollutant on the HAPs of interest lists.

- A CC member representing environmental organizations asked if the Boiler WG had considered polychlorinated biphenyls (PCBs) for the list of HAPs of interest for natural gas because natural gas pipelines may be contaminated with PCBs. The member referred to the recent "PCB Megarule".

- A public commentor, Andy Bodnarik, a member of the Boiler WG, responded to the CC member's question regarding PCBs in natural gas emissions. Mr. Bodnarik indicated that PCBs were on the initial list of HAPs but were dropped off the list for natural gas because emissions were below the impact levels when the screening analyses were done. Another CC member stated that PCBs would not be expected from natural gas firing.

- Decision: The CC reached consensus to forward the paper on HAPs of interest for fossil fuel-fired boilers to EPA as a CC recommendation.

2.5 TURBINE WORK GROUP CLOSURE PRESENTATION ON COST OF HAP EMISSION CONTROL AND CC RECOMMENDATION

- The Combustion Turbine Work Group (CTWG) gave a closure presentation on the cost of HAP emission controls. The presentation and background document are provided as Attachments 9 and 10, respectively.

- The CTWG outlined the approach used in the analyses. The CTWG discussed how it determined baseline emissions, oxidation catalyst costs, HAPs reduction performance, and cost effectiveness. The CTWG also discussed the complicating factors associated with doing these type of analyses.

- The conclusions of the report present six base case costs expressed as $/Mg total HAP along with the associated complicating factors. The CTWG requested that the CC forward this document to EPA to be considered in any above-the-floor MACT analyses.

- A CC member commented that the cost analysis should not automatically include an annual stack test because there may be less burdensome ways of determining compliance. A CTWG member responded that for completeness, the analysis included the tests because there would likely be some costs to monitor or determine compliance; however, the test costs are a small percentage of total annual costs, so changing these costs would not significantly change the results of the analysis. An EPA representative clarified that the cost assumption does not mean the rule will require annual testing. Compliance determination methods will be considered during rule development.

- In response to a question from a CC member about the role the Economics WG played in this cost effectiveness analysis, EPA representatives pointed out that the Economics WG was not involved in this analysis because this is strictly a cost analysis. Developing costs and control options is the responsibility of the technical group and the economics group does economic impact and benefits analyses.

- Some CC members representing various stakeholder groups did not agree with the characterization of the CTWG analysis as a cost effectiveness analysis because the members believed that cost effectiveness analysis should include a review of benefits. Benefits mentioned include CO reduction, non-HAP VOC reduction, health benefits, and energy impacts.

- An EPA representative clarified that there is a difference between a cost effectiveness analysis which assesses the $/ton HAP and a cost benefits analysis which looks at other benefits such as control of secondary pollutants like CO. A CC member pointed out that the term cost effectiveness is used differently by different people and could be misleading.

- A CC member commented that the use of the highest emission factor for each pollutant to determine baseline emissions may be appropriate for a screening study, but should be refined if the cost effectiveness numbers are used for decision-making.

- A member of the CTWG pointed out that the purpose of the document was to present the information that gives a rough range of cost and emission reduction and not draw conclusions as to what is cost effective. The member stated that the complicating factors discussion in the document addresses the fact that the cost effectiveness could increase or decrease based on how these factors are handled.

- In response to a question, an EPA representative discussed the role the Unfunded Mandates Reform Act (UMRA) plays in EPA's decision making process for above-the-floor MACT. UMRA applies to regulations that impose requirements that may result in the expenditure by State, local, or tribal governments or by the private sector of $100 million or more and it requires EPA to select either the least costly, least burdensome, or most cost effective option, or explain its rationale for choosing something different. An EPA representative also pointed out that cost effectiveness is just one of many factors EPA considers in making decisions on whether to go beyond the floor in setting MACT standards.

- A CC member suggested that the paper be forwarded to EPA with transmittal language that characterizes it as a cost analysis as opposed to a cost effectiveness analysis. This would not require any edits to be made to the paper itself.

- A public commentor, Jim McCarthy of GRI, pointed out that there are currently no controls on most existing turbines. The costs presented in the paper would be the cost of complying with the ICCR regulations. Mr. McCarthy also pointed out that much of the information included in the CTWG report is on the Economic Analyses WG list of necessary input information to a cost benefits analysis. In response to the question from a CC member about the testing costs included in the CTWG report, Mr. McCarthy indicated that complying with a MACT standard would require some type of monitoring so the CTWG included the cost of the most simplistic monitoring that might be required and that including this cost is consistent with the EPA/OAQPS cost manual.

- A public commentor, Andy Bodnarik, a member of the Boiler WG, commented that the paper was a good status report based on the information that the CTWG had available. It also does a good job of pointing out areas for further investigation and refinement.

- A public commentor, Jeff Wheelis of Rolls Royce, pointed out that both emission tests used in the analysis of oxidation catalysts also had water injection. He stated that water injection increases emissions of CO and affects the relationship of CO to HAPs. CO catalysts were added to reduce the elevated CO emissions.
- A public commentor, David Marrack, a member of the Boiler and Incinerator WG's, stated that ICCR sources need to be tested simultaneously for the effects of various controls on HAPs (especially polynuclear aromatic hydrocarbons (PAH)) and criteria pollutants (e.g. NOx and CO).

- A public commentor, Jim Seebold, a member of the Process Heater WG, stated that CO oxidation catalysts appear to be a very expensive method for controlling formaldehyde.

- Decision: The CC reached consensus to forward the paper on oxidation catalyst control for turbines to EPA as a CC recommendation. The transmittal letter will characterize the report as a “cost analysis”. The transmittal letter will also refer to the full meeting minutes for a summary of CC discussion on the paper.

2.6 TESTING AND MONITORING PROTOCOL WORK GROUP CLOSURE PRESENTATION ON USING EMISSIONS DATABASES CONTAINING NON-DETECTION VALUES AND CC RECOMMENDATION

- The Testing and Monitoring Protocol Work Group (TMPWG) discussed the WG’s guidance document on interpreting and using emissions databases containing non-detection values. This document was also discussed at the November 17 and 18, 1997 CC meeting but was not transmitted to EPA by the CC because it was issued as guidance to the Source WGs. The document is provided as Attachment 11.

- The TMPWG indicated that this document was originally prepared at the request of the CC because of the large number of non-detects in the ICCR emissions database. The TMPWG provided a brief overview of the document.

- A CC member representing environmental organizations emphasized that in developing regulations the Agency must be aware of pollutants that are a concern even in very small quantities.

- An EPA representative indicated that the Agency would go through a process of determining which HAPs to regulate. The Agency would consider what HAPs might be expected, determine testing needs, and review all the available emissions data, pollutant toxicity, impacts and other factors when making its decisions.

- A CC member pointed out that the ICCR can not solve the problem of pollutants of concern that are emitted at very low levels because there are currently no test methods available for measuring these levels. Test methods are improving over time.

- Some CC members pointed out that the TMPWG paper assumes that Source WG’s know what constitutes a critical concentration level. Another CC member responded that this should not be a consideration because when testing, the smallest practical detection limits should be used.

- A public commentor, Lawrence Otwell, a member of the TMPWG, responded that test methods have a limited range of accuracy. If the source being tested has a high concentration of emissions, a method for detecting extremely low levels of emissions would be “washed out”.

- A public commentor, David Marrack, a member of the Boiler and Incinerator WG's, stated that the biological effects of many pollutants are unknown and it would be a presumption to try to establish critical concentrations without additional data. He and a CC member suggested EPA should act quickly to adopt new test methods that are more sensitive than EPA reference methods.

- Decision: The CC reached consensus to forward the TMPWG document on using databases containing non-detection values to the EPA as a CC recommendation.

2.7 ENGINE WORK GROUP CLOSURE PRESENTATION ON RICH BURN ENGINE DEFINITION AND CC RECOMMENDATION

- The reciprocating internal combustion engine (RICE) WG gave a closure presentation on possible regulatory definitions for rich burn engines. The WG agreed that a regulatory definition is necessary and that such a definition should capture the engineering differences between a lean burn and a rich burn engine. The RICE WG did not reach consensus on a single regulatory definition of rich burn engines. The document summarizes the WG discussions, outlines six different approaches to defining rich burn engines, and presents several goals of a regulatory definition agreed upon by the RICE WG. The presentation and document are provided as Attachments 12 and 13, respectively.

- A CC member representing an industry group commented that if the regulatory definition that seems most appropriate for rich burn engines is not consistent with the subcategory definitions used in the MACT floor analysis, the MACT floor would need to be reevaluated using the new definition. A member of the RICE WG indicated that the definition chosen would not change the subcategory evaluations because there is not enough precision in the ICCR population database to determine how different definitions might affect the population of the subcategory. The RICE WG believes that the rich burn designation in the ICCR population database is based primarily on manufacturer's specifications.

- A CC member pointed out that it would be difficult to measure 'lambda' for natural gas precisely enough to use as part of the definition. The member pointed out that 'lambda' is based on the oxygen content of the fuel and the oxygen content of natural gas differs.

- A CC member representing affected sources commented that the definition should recognize that some engines that were designed to be rich burn are being converted to lean-burn in order to meet criteria pollutant regulations, not to circumvent being classified as a rich burn engine.

- A CC member representing State/local Agencies asked why 1 percent oxygen in the exhaust gas was not determined to be the most appropriate definition. A member of the RICE WG indicated that some WG members felt that the 1 percent level was based more on a control technology than on the engine design. Another CC member representing State/local agencies indicated that percent oxygen should be included in the definition so that State regulators have a measurable parameter to use for inspections.

- A public commentor, David Marrack, a member of the Boiler and Incinerator WG's, stated that the manufacturer's label is not adequate to define an engine as rich burn. The definition should include some type of percent oxygen criteria. He also pointed out that CO emissions might be used to characterize engines as rich burn or lean burn.

- Decision: The CC reached consensus to forward the paper on the definition of rich burn engines to EPA as a CC recommendation. A member stressed the importance of consistency between the definition and the subcategory analysis.

2.8 ENGINE WORK GROUP CLOSURE PRESENTATION ON ASSESSMENT OF EMISSION DATABASE AND CC RECOMMENDATION

- The RICE WG gave a closure presentation on its assessment of the ICCR Emissions database which outlines the work done by the WG throughout the ICCR process. The presentation and document are provided as Attachments 14 and 15, respectively.

- The RICE WG indicated that the test plan recommended to EPA by the CC would fill many of the data gaps identified in the data assessment. The paper concludes that EPA should conduct the RICE test plan and rely on the results for regulatory development for RICE.

- There were no comments on this RICE document from CC members or members of the public.

- Decision: The CC reached consensus to forward the paper on the assessment of the emissions database for RICE to EPA as a CC recommendation.

2.9 ENGINE WORK GROUP CLOSURE PRESENTATION ON ABOVE-THE-FLOOR MACT OPTIONS FOR DIGESTER AND LANDFILL GAS COMBUSTION AND CC RECOMMENDATION

- The RICE WG gave a closure presentation on above-the-floor MACT options for digester and landfill gas combustion. The presentation and document are provided as Attachments 16 and 17, respectively.

- The WG pointed out that previous analyses indicated that there was no MACT floor for these sources and this paper deals with the WG's further analysis of above-the-floor control options. The conclusion of this presentation is that the RICE WG believes that the air injection and catalytic controls for rich burn engines have not been proven to be reliable above-the-floor controls. The WG does suggest getting more information on the lean burn engine/afterburner control system for landfill gas engines.

- The presenter noted that the afterburners at Orange County (Prima Deschecha) landfill discussed on page 4 of the document have not yet been installed. The landfill plans to install them soon.

- A CC member representing environmental organizations stated that it was troublesome that no maintenance practices were incorporated into the MACT floor for these sources and questioned whether there was a need for additional test data on these sources. Another CC member representing State/local agencies reiterated the concern related to not including maintenance practices in the MACT floor.

- A member of the RICE WG responded that this presentation deals with above-the-floor control options only. The rationale document on the MACT floor for these sources was discussed at the last CC meeting, when the CC decided to forward it to EPA as a CC recommendation. The WG's consideration of pollution prevention is discussed in a work-in-progress paper.

- A member representing State/local Agencies disagreed with the statement on page 9 of the slide presentation that says, "cost effectiveness is likely to be different". The member suggested that this should state, "cost effectiveness might be different".

- A CC member also suggested changing the last sentence at the bottom of page 4 of the document to read, "may be" instead of "will likely be". Other CC members and the RICE WG representatives agreed to make this change. This change has been made in Attachment 17.

- A public commentor, Prakasam Tata, a member of the Boiler WG, stated that although the RICE paper groups digester gas and landfill gas, there is a difference in these two gases in terms of HAP emissions.

- A CC member representing environmental organizations stated that he would not hold up this document from being forwarded to EPA, but he still thinks there appears to be differences in HAP emissions from some of these units and EPA should investigate further whether there is a floor for landfill and digester gas-fired engines.

- <u>Decision</u>: The CC reached consensus to forward the paper on above-the-floor technologies for digester and landfill gas RICE to the EPA as a CC recommendation. One wording change was agreed upon. The transmittal letter will also refer to the full meeting minutes for additional CC discussion.

2.10 WORKS-IN-PROGRESS AND DATA/INFORMATION ITEMS

Procedures for Transmitting Works-In-Progress to EPA

- The Facilitator and the EPA CC co-chair reminded the CC that at the July CC meeting, the CC reached consensus on defining "works-in-progress" as items that WG's were not able to complete prior to the conclusion of the Federal Advisory Committee Act (FACA) process. Therefore, these items may contain partial analyses, the rationales may not be fully documented or reviewed, and issues needing investigation may remain. However, these items may provide a foundation for further work, or ideas that the CC may want EPA to consider as it develops regulations for the ICCR sources. The facilitator also noted that at the July 1998 CC meeting, the CC had reached consensus on forwarding works-in-progress and data/information items to EPA for consideration -- not as CC consensus recommendations -- to ensure that EPA can consider the work done by the WG's, as appropriate, and that WG efforts are not lost. The Committee, including the EPA representative on the Committee, agreed that these items would carry less weight than CC consensus recommendations. Works-in-progress would carry the same weight as comments EPA receives from an individual.

- The CC began discussing works-in-progress, and several important procedural issues were raised. Committee members were concerned that some of the works-in-progress contain conclusory statements that some members of the CC do not agree with or contain insufficient supporting information to determine if a conclusion is correct. Some of the items also use language like "recommendation". There was concern that these works-in-progress could be mistaken as CC recommendations to EPA, whereas they are actually preliminary recommendations from a WG or Subgroup to the CC. As indicated in the definition of "works-in-progress," the CC has not deliberated on these works nor developed CC recommendations. Members were also concerned that works-in-progress might be given more weight than individual comments. An EPA representative stated that EPA would give works-in-progress no more weight than comments submitted by any individual. CC members and others are free to send EPA individual comments on any works-in-progress.

- A CC member suggested deleting WG recommendations from the works-in-progress. An EPA WG co-chair stated that the WG members had considerable technical expertise and she believed it would be beneficial to the regulatory development effort if EPA was able to consider the preliminary conclusions and suggestions from WG's that are contained in the various works-in-progress. Some other WG and CC members also objected to deletions. A CC member pointed out that some WG's did not have a balance of stakeholder interests.

- An EPA representative suggested the CC co-chairs revise the documents to change them from WG to CC products and to change any language that implied a "recommendation" to a "comment", or "thought" or "idea". However, several CC members were uncomfortable with this, as it might be perceived that the CC was presenting to EPA incomplete WG products as products that had received full consideration by the CC. Some also were concerned that it would be hard to find every place where the language should be changed. There was also concern that changing the language could change the meaning or make it unclear as to what the WG's had concluded. They asked the EPA representative to consider if such editing was necessary if a transmittal letter clearly indicated that the items were WG works-in-progress that the CC was forwarding to EPA for its consideration only, and not as CC recommendations.

- After additional consideration, the CC co-chairs outlined two procedural options for transmitting works-in-progress to EPA. The first option, supported by several CC members, was to agree upon transmittal language and footers to make it clear that these are WG works-in-progress the CC was forwarding to EPA for its consideration as appropriate, that the CC did not reach closure on these products, and that they are not CC recommendations. The WG documents could then be forwarded without any other changes.

- The second option would be to utilize the procedures on pages 30-31 of the ICCR Document for when consensus is not reached and forward to EPA the works-in-progress with the various divergent viewpoints. By using the procedures for handling noncensus with majority and minority opinions, any member of the CC could have an issue elevated to EPA for resolution. Those that disagree that the item should be forwarded to EPA can develop minority or majority position papers stating why it should not be considered or what objections they have to the specific work-in-progress.

- A public commenter, Norbert Dee of the National Petroleum Refiners Association (NPRA), suggested that works-in-progress should be characterized as "comments", rather than "thoughts". This is consistent with the terminology of "public comments" used in rulemaking processes. He also stated that the transmittal letter option comes closest to the original spirit and intent of the ICCR and the goal of moving forward.

- Another public commenter, Lee Gilmer, a member of the Process Heater WG agreed that the documents represent more data and analyses than the word "thought" implies. He supported the suggestion to not change or delete statements in the works-in-progress but to develop a clear transmittal letter explaining that they do not represent closure or CC recommendations.

- A public commenter, Andy Bodnarik, a member of the Boiler WG, said some works-in-progress contain recommendations for where further analysis is needed, and it is important that EPA be able to consider these types of recommendations. He was concerned about editing that might remove or change such suggestions.

- A CC member representing environmental organizations read a statement that he believed some of the suggestions made by EPA staff during the discussion of procedures were inconsistent with the works-in-progress procedures agreed upon at the July meeting. He objected to forcing closure, and was also concerned that EPA staff may give too much weight to WG works-in-progress. When asked what procedure he recommended, the member replied that he would favor the transmittal language option but would need to see the language in writing.

- An EPA representative stated in response to the CC member's comment that EPA will give the works-in-progress no more weight than any other comments submitted to EPA by individuals or organizations, because it was not a consensus recommendation of all stakeholders affected by the matter. Also, the transmittal letter would make it clear that the item is a WG work-in-progress forwarded to EPA by the CC for its consideration as it continues regulatory development and not a CC consensus recommendation as to how EPA should act regarding a particular matter.

- Lee Gilmer stated that the option of developing a transmittal letter without editing the works-in-progress matches the Process Heater WG's understanding of the procedure agreed upon at the July WG meeting.

- A public commenter, Dr. David Marrack, a member of the Incinerator and Boiler WG's said that what is causing concern is the transmittal of opinions, not data. He suggested EPA maintain a separate TTN web site for the ICCR where all documents, meeting and telecon minutes, and other information relevant to ICCR is posted and available to the public. Then the public will be able to send in comments on these items.

- At the request of the facilitator, an EPA representative read the procedures the CC had adopted at the July 1998 CC meeting, as documented on pages 4 and 5 of the July meeting minutes:

  "It was decided that WG work products be divided into three categories:

  1. Closure items,
  2. Works in Progress
     - ongoing (under discussion within WG's)
     - new, and
  3. Data/information

  For closure items, the same procedures currently in use will apply. They must be posted to the TTN one week in advance of the meeting. The CC will develop recommendations for EPA regarding these items and transmit the recommendations and items to EPA. These recommendations will be given "great weight" by EPA.

  Works-in-progress include draft and incomplete items on which the WG has not reached closure. These items will be posted one week prior to the meeting as much as possible, discussed at the CC meeting, and transmitted to EPA "for consideration," not as a recommendation. Members of the CC may attach comments to the works-in-progress or send in comments to EPA to a later date. Compared to closure items, these items will not have "great weight." They will have as much weight as comments received from an individual. Any comments by individual CC members will have similar weight."

- Decision: With this background in mind, the CC agreed upon the following transmittal language for a cover memo for the works-in-progress and on footer language for a footer that will go on each page of each work-in-progress document. The works-in-progress will not be edited. Any person can send EPA comments on any of the work-in-progress or data/information items. Substantive comments on the works-in-progress or data/information items made during the CC meeting will be documented for the record in the meeting minutes. EPA will give comments that are sent later or made during the meeting as much weight as the works-in-progress.

  Cover Memo:
  "The CC forwards the following Work Group works-in-progress to U.S. EPA for appropriate consideration, not as recommendations, consistent with the discussion at its July 1998 CC meeting (see minutes, p. 4-5). Statements in these documents may not represent the opinions of all CC members. Works-in-progress include draft and incomplete items on which the CC has not reached closure. These items have only as much weight as individual comments EPA receives from any individual."

  Footer for each page:
  "This document is a Work Group work-in-progress forwarded to U.S. EPA by the ICCR Advisory Committee. The Advisory Committee did not reach closure on this document prior to the Advisory Committee's termination. Consequently, nothing herein constitutes a recommendation from the Advisory Committee and individual members of the Committee may not agree with all of the statements herein."

- One CC member representing an environmental organization wanted to state for the record that he thinks the WG works-in-progress are valuable and should go to EPA; however, he never foresaw the ICCR process ending in this way and he has some discomfort with the process for forwarding these items the CC has not considered. The CC member also stated that he thought the proposed language for the transmittal letter and footer did not adequately convey that not all CC members agreed with everything in each work-in-progress; however, upon a rereading of the language, the CC member indicated he had misread the language and his concerns were, in fact, addressed by the proposed language.

- The facilitator specifically asked each CC member whether there was consensus to move forward with the process decision described as Option 1. All CC members indicated their agreement.

Decision to Transmit Works-In-Progress and Data Information Items to EPA

- The CC reached consensus to transmit all of the data/information items (listed on pages 5 through 7 of the Agenda in Attachment 2) to EPA for consideration using the agreed upon transmittal language and footer.

- The CC reached consensus to transmit all of the works-in-progress (listed on pages 3 and 4 of the Agenda in Attachment 2) to EPA for consideration using the agreed upon transmittal language and footer.

- The works-in-progress and data/information items will be put in the ICCR docket after the footers and cover memo have been added. They are not attached to this meeting summary.

<u>Presentations and Comments on Individual Works-In-Progress or Data/Information Items</u>

- Several CC members made comments for the record on individual works-in-progress or data/information items that were forwarded to EPA for consideration. These are documented below.

<u>Dioxin Primer</u>

- An EPA representative made a brief presentation to remind the CC of the dioxin primer (Attachment 18). The CC previously forwarded this primer, with agreed-upon transmittal language to the Source WG's for consideration. The same transmittal language will also be forwarded to EPA.

- A CC member representing the pulp and paper industry stated that his organization had a problem with the characterization of wood in this presentation as having moderate to high dioxin emissions. The pulp and paper industry met with EER, the EPA contractor for the dioxin primer, and found that these characterizations were based more on theoretical chemistry than on test data. The National Council of Air and Stream Improvement (NCASI) provided dioxin data for wood to EPA, the Boiler WG, and the environmental caucus that shows a lower dioxin emission potential than was indicated in the dioxin primer.

- A public commentor, David Marrack, a member of the Boiler and Incinerator WG's, wanted to make sure that along with the dioxin presentation, EPA will consider the comments on the dioxin primer made at the September 1997 CC meeting when the primer was presented. These comments are documented in the meeting minutes.

<u>Pollution Prevention Subgroup Works-in-Progress</u>

- A member of the Pollution Prevention (P2) subgroup indicated that the works-in-progress included the materials on operator training, GCP, metrics, and regulatory approaches. The member pointed out that when these materials were forwarded to the Source WG's, there were cautions added by the CC to consider the appropriateness of these P2 options for the specific source categories. These cautions will also be forwarded to EPA.

- A CC member and industry representative commented that the definition of an operator used in the P2 papers is very comprehensive. The member pointed out that the in the

RAP, the IWG suggests that EPA will need to consider a more specific definition later in the regulatory process.

RICE WG Works-In-Progress

- A RICE WG member made a presentation about the four RICE WG works-in-progress (Attachment 19).

- A CC member representing environmental organizations disagreed with the conclusion in the RICE P2 paper that indicates that operator training is prohibitively expensive because the paper contains no cost information to support this conclusion and the Economic Analyses WG was not consulted on the issue. The member pointed out that the P2 paper is inconsistent when it discusses the usefulness of operating manuals, but then recommends no mandatory operator training program. The member also indicated that there is no analysis of the different metrics options and their applicability in the RICE P2 document to support the WG's conclusion that metrics could not be used. The member also stated that fuel switching could reduce emissions and should not be discounted. The member stated that there were many other conclusion statements within the RICE documents that were not supported by the data presented in these documents.

- Another CC member responded that some of the concerns expressed deal with maintenance rather than operating issues, and pointed out that the RICE documents discuss maintenance. The environmental organization representative replied that EPA should consider how regulations can ensure that maintenance procedures get done and whether training of maintenance personnel should be part of operating training.

- A CC member representing State/local agencies pointed out that the RICE paper on GCP discusses recording operating parameters suggested by the manufacturer. The member indicated that the statement should say, "at a minimum, these GCP methods should be required (i.e. air to fuel ratio, timing, etc.)" because older operating manuals might not cover these. The member expressed objections to the other conclusion statements in the RICE WG works-in-progress including five conclusion statements in the RICE P2 document.

- A CC member representing industry indicated that there is no inconsistency in the RICE reports regarding P2 because many of the adjustments considered to be P2 are set automatically through new engine technology. The member also stated that operator training was impractical because it would be necessary to train operators on hundreds of different engine models.

- An EPA representative asked the RICE WG if the letters requesting costs from vendors were sent directly from EPA. A member of the RICE WG indicated that the letters had been sent by EPA.

- A public commentor, David Marrack, a member of the Boiler and Incinerator WG's, disagreed with the conclusions on operator training in the RICE report, and suggested that maintenance personnel should be trained and certified for the type of engine they are working on. Dr. Marrack also pointed out that the RICE report on P2 did not address the two different means of fuel switching, (1) switch from diesel fuel to gas and (2) change composition of the diesel fuel to lower the sulfur and aromatic constituents. He noted that the California Air Resources Board (CARB) has investigated this.

Process Heater WG Works-in-Progress

- Regarding the rationale for MACT from indirect-fired process heaters which is based on the Petroleum Environmental Research Forum (PERF) data, a CC member representing environmental organizations indicated that the WG lacks the emissions data to support its conclusions. The CC member further stated that although the Process Heater WG suffers from a lack of data and the WG does not know why the available data are greatly varied, the WG did not advance a test plan to deal with its data gaps. She asked that EPA consider the comments made at a previous CC meeting when the Process Heater WG gave an informational presentation on this topic.

Boiler WG Works-in-Progress

- Regarding the Boiler WG work-in-progress on a *de minimis* level for Section 129 materials, a CC member representing environmental organizations does not support the 5 percent *de minimis* level provided by the Boiler WG. The CC member pointed out that the Boiler WG test plan results might support some *de minimis* level, but there is currently no data to support a 5 percent *de minimis* cutoff for Section 129 sources.

- Another CC member representing environmental organizations expressed disagreement with the Boiler WG paper on *de minimis* levels for Section 129 sources. The CC member believes that the Agency does not have the legal authority to establish a *de minimis* level for Section 129 sources.

2.11 ENVIRONMENTAL CAUCUS WORK-IN-PROGRESS ON ENVIRONMENTAL JUSTICE

- The Environmental Caucus presented a work-in-progress on environmental justice (EJ) and requested that it be forwarded to EPA for consideration. The document is provided as Attachment 20.

- The Environmental Caucus reviewed the nine background points on the back of the proposal, and emphasized that the proposal only requires dissemination of information and does not impose any restrictions. The Environmental Caucus also indicated that it would reword the title of the proposal to be clear it is from the Environmental Caucus and not the CC.

- The Environmental Caucus also indicated that this proposal had been circulated widely among environmental activists outside the ICCR process and the proposal had received support.

- A CC member representing industry expressed concern over the detailed nature of the proposal. The member indicated that industry does not agree that providing the information outlined in the proposal would be simple and inexpensive. The member stated it was unclear why the census information needed to be repeated in every permit, because this information would be available to EPA and the States when evaluating EJ. Also, a description of facilities in the 50km area is very difficult because the information is constantly changing. This information would be more readily available to regulators than to industry. The member also pointed out that the Title V program is already behind schedule and should not be burdened further with more requirements. The member concluded by indicating that it is premature to propose specifics to be incorporated into the ICCR until the general procedural and policy questions about how to evaluate EJ and who is responsible for providing the necessary information are fleshed out at the national level. The member noted that a methodology for performing EJ assessments is at the Science Advisory Board for review, and there are national FACAs assessing EJ. He expressed agreement with comments made by industry representatives at the July 1998 CC meeting.

- A CC member representing State/local agencies indicated that State agencies wanted to see EPA address EJ as a separate rulemaking because State/local agencies want to review and comment on what their role would be. The member pointed out that if this proposal applied to every Title V facility with an ICCR source, it would apply to almost every Title V permit issued. The State agencies need to consider how to implement policy on EJ and what additional resources would be needed. The CC member also suggested that the Environmental Caucus submit a list of the environmental groups that reviewed and support the proposal so that other CC members have this information.

- Another CC member representing State/local agencies expressed similar concerns about the proposal. The member indicated that Title V is probably the right vehicle for EJ concerns but that the timing is a problem because the State agencies are still in the permitting process. The member suggested that implementing this type of proposal during five-year permit renewal would make more sense.

- A CC member representing a government agency that operates combustion units stated that the basic problem with the proposal is that it is tied to the Title VI Interim Guidance. The member indicated that until the EJ implementation FACA deals with all the comments received on the Interim Guidance, this proposal is premature. The member stated that one problem with the Interim Guidance is that it is entirely after-the-fact and does nothing pro-active to help a local agency avoid an EJ lawsuit. The member appreciated the concept of making facility information available to the public up-front, but was concerned that requiring this information for every facility would further bog down the Title V program. He noted that some industry representatives in California have suggested a trigger so that detailed information is required for some, but not all, facilities.

- A member of the Environmental Caucus responded that the proposal is not tied to the Interim Guidance but it does not contradict anything in the Interim Guidance. The proposal highlights some of the same information that the Interim Guidance states is important for assessing EJ issues.

- A CC member representing a State/local agency indicated that an Urban Air Toxics approach may be a good method for dealing with EJ issues. He sees the Environmental Caucus proposal as part of an overall process, but feels that the overall process needs to be worked out before such a proposal is adopted.

- A public commentor, Norbert Dee, representing NPRA, asked if this document would be characterized as being a work-in-progress or a comment from the Environmental Caucus. He noted that a caucus is different from a WG.

- A public commentor, Bob Bessette, representing the Council of Industrial Boiler Owners (CIBO), questioned whether it was appropriate to transmit the EJ proposal to EPA. Mr. Bessette indicated that it might be more appropriately transmitted as a public comment. He believed the thinking on EJ is not yet completed and it is premature to act on the proposal.

- Two Environmental Caucus members replied that the caucus brought forward an EJ proposal at the July CC meeting and voluntarily considered comments made at the meeting to create the current proposal rather than forcing majority and minority recommendations at the July meeting. They understood that at the July meeting, the CC requested the caucus to continue to work on the proposal with the understanding that it could be transmitted as a work-in-progress.

- A public commentor, Lee Gilmer, a member of the Process Heater WG, stated that he had serious concerns with the proposal because there are already two EPA EJ advisory committees that are ongoing. This ICCR proposal could be contradictory to the results of these committees. Mr. Gilmer suggested that the language used for the transmittal of this proposal characterize it as non-consensus and made it clear it is not a CC recommendation.

- A member of the Environmental Caucus clarified that 'background material' refers to the back page of the proposal and the 3 to 4 page document presented at the September 1997 CC meeting. (These items are included in Attachment 20.)

- <u>Decision</u>: The CC reached consensus to transmit the Environmental Caucus EJ proposal to EPA for consideration using the following transmittal language:

> "The CC transmits the Environmental Caucus EJ proposal, background material, and the minutes from the CC discussions about this topic at the July and September meetings to EPA for consideration."

The same footer will be put on each page as on the other works-in-progress, except the words "Work Group" will be changed to "Environmental Caucus" in the footer.

3.0 CONCLUDING REMARKS

- As documented in the July 1998 CC meeting minutes, EPA did not renew the FACA charter for the ICCR Advisory Committee (i.e., the CC). The 2-year charter expires September 20, 1998. Therefore, this September 1998 CC meeting was the final ICCR meeting.

- Bob Bessette, of CIBO, presented award certificates to Fred Porter and Rich Anderson for their service as CC co-chairs over the past 2 years. Mr. Bessette stated that the ICCR process had exceeded the expectations of those who were involved at the start. He observed that participants from diverse stakeholder groups who has not previously talked with one another were working together and developing an understanding of each other's concerns. He saw a cooperative spirit in the CC and WG meetings, and believed the ICCR process accomplished a lot. He thanked Mr. Porter and Mr. Anderson for their leadership in this process. Others concurred with Mr. Bessette's statements.

- The CC co-chairs and facilitators thanked the members for their participation. An EPA representative expressed hope that individual members would remain involved in the source category rulemakings through the mechanisms provided by the normal regulatory development process. (Mechanisms for future involvement are further described in the July 1998 CC meeting minutes.)

These minutes represent an accurate description of matters discussed and conclusions reached and include a copy of all reports received, issued, or approved at the September 16 - 17, 1998 meeting of the Coordinating Committee. Fred Porter, EPA Co-Chair.

LIST OF ATTACHMENTS

Attachment 1	Attendance List for September 16 and 17, 1998, Coordinating Committee Meeting
Attachment 2	Meeting Agenda
Attachment 3	Flash Minutes of September 16 & 17, 1998, Coordinating Committee Meeting
Attachment 4	Regulatory Alternatives Paper (Closure Item)
Attachment 5	Boiler Work Group Presentation on Preliminary MACT Floors For Natural Gas and Fuel Oil-Fired Boilers
Attachment 6	Paper on Preliminary MACT Floors For Natural Gas and Fuel Oil-Fired Boilers (Closure Item)

Attachment 7	Boiler Work Group Presentation on HAPs of Interest For Fossil Fuel-Fired Boilers
Attachment 8	Paper on HAPs of Interest for Fossil Fuel-Fired Boilers (Closure Item)
Attachment 9	Combustion Turbine Work Group Presentation on Cost of HAP Emission Controls
Attachment 10	Paper on Cost of HAP Emission Controls for Combustion Turbines (Closure Item)
Attachment 11	Interpreting and Using Emissions Databases Containing Non-Detection Values (Closure Item)
Attachment 12	RICE Work Group Presentation on Rich Burn Engine Definition
Attachment 13	Paper on Rich Burn Engine Definition (Closure Item)
Attachment 14	RICE Work Group Presentation on Emissions Database Assessment
Attachment 15	Paper on Assessment of RICE Emissions Database (Closure Item)
Attachment 16	RICE Work Group Presentation on Above the Floor MACT Options for Landfill and Digester Gas
Attachment 17	Paper on Above the Floor MACT Options for Landfill and Digester Gas-Fired RICE (Closure Item)
Attachment 18	Presentation on Dioxin Primer Data/Information Item
Attachment 19	Presentation on RICE Work Group (Works-In-Progress)
Attachment 20	Environmental Caucus Environmental Justice Proposal (Work-In-Progress) and Background Materials

Attachment 1

Attendance List for September 16 and 17, 1998, Coordinating Committee Meeting

Industrial Combustion Coordinating Rulemaking
Coordinating Committee Attendance List
Wednesday, September 16, 1998

Greg Adams
Amanda Agnew
Rich Anderson
Todd Barker
Ethan Begg
Doug Bell
Beth Berglund
Bob Bessette
Andy Bodnarik
Atly Brasher
Richard Brown
Mark Bryson
Christy Burlew
Mark Calmes
A. J. Cherian
Michael Clowers
Sam Clowney
Linda Coerr
Stan Coerr
Rick Crume
Norbert Dee
John deRuyter
Lachhman Dev
Gerald Doddington
Don Dowdall
Jim Eddinger
Paul Eisele
Chuck Feerick
Frank Ferraro
Michael Fisher
Ron Foskey
Leslye Fraser
Bill Freeman
Gordon Gaetke
Mike Gallaher
Greg Gesell
Lee Gilmer
Ted Guth
Keith Harley
Craig Harrison
Terry Harrison
Don Herndon
Michael Hewett
Peter Hill
Michael Horowitz
Jason Huckaby
Tim Hunt
John Huyler
Alex Johnson
David R. Jones
Mark Kataoka
Robert Kaufmann
John Klein
Dennis Knisley
Mary Lalley
Keri Leach
Alison Ling
Dennis Marietta
David Marrack
Bill Maxwell
Doris Maxwell
Jim McCarthy
Tom McGrath
Ruth Mead
Bob Morris
Norm Morrow
Vick Newsom
Bill O'Sullivan
John Ogle
Roy Oommen
Lawrence Otwell
Bob Palzer
John Paul
Bill Perdue
Frederick Phillips
Marc Phillips
Fred Porter
Brian Quil
Ed Repa
Brahim Richani
Ralph Roberson
Sims Roy
Glenn Sappie
David Schanbacher
Marvin Schorr
Jim Seebold
Gunseli Shareef
Jeff Shumaker
George Smith
Jeffrey Smith
Jennifer Snyder
Mike Soots
John Stephens
James Stumbar
Prakasam Tata
Larry Thompson
Dick Van Frank
Bob Walker
Tom Walton
Wei-Yeong Wang
Bill Wiley
Jane Williams
Jeff Willis
Vladimir Zaytseff

Industrial Combustion Coordinating Rulemaking
Coordinating Committee Attendance List
Thursday, September 17, 1998

Greg Adams
Amanda Agnew
Dave Ailor
Rich Anderson
Todd Barker
Ethan Begg
Doug Bell
Beth Berglund
Bob Bessette
Andrew Bodnarik
Atly Brasher
Richard Brown
Mark Bryson
Christy Burlew
Mark Calmes
Sam Clowney
Linda Coerr
Stan Coerr
Rick Crume
Norbert Dee
John deRuyter
Lachhman Dev
Gerald Doddington
Donald Dowdall
Jim Eddinger
Paul Eisele
Chuck Feerick
Michael Fisher
Ron Foskey
Leslye Fraser
Drew Frye
Gordon Gaetke
Mike Gallaher
Lee Gilmer
Ted Guth
Keith Harley
Craig Harrison
Terry Harrison
Dan Herndon
Michael Hewett
Peter Hill
Jason Huckaby
Tim Hunt
John Huyler
Alex Johnson
David R. Jones
Robert Kaufmann
John Klein
Dennis Knisley
Mary Lalley
Keri Leach
Alison Ling
David Marrack
Bill Maxwell
Jim McCarthy
Tom McGrath
Ruth Mead
Bob Morris
Norm Morrow
Russell Mosher
Vick Newsom
Bill O'Sullivan
John Ogle
Roy Oommen
Bob Palzer
John Paul
Frederick Phillips
Fred Porter
Brian Quil
Ed Repa
Sims Roy
Glenn Sappie
David Schanbacher
Marvin Schorr
Jim Seebold
Gunseli Shareef
Jeff Shumaker
Jeffrey Smith
James Stumbar
Prakasam Taka
Dick Van Frank
Bob Walker
Wei-Yeong Wang
Jane Williams
Jeff Willis
Vladimir Zaytseff

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Attachment 2

Meeting Agenda

Third Draft: September 4, 1998

INDUSTRIAL COMBUSTION COORDINATED RULEMAKING
Coordinating Committee
September 16-17, 1998
Durham, North Carolina

Durham Marriott at the Civic Center
201 Foster Street
(919) 768-6000

<u>Notes</u>:

- Materials posted to the TTN one week or more prior to the meeting will not be provided at the meeting. Please bring your own copies. See below for location of documents that will be used during the meeting.

- A hard copy of material not available electronically prior to the meeting will be available during the meeting for review.

- "Business Casual" is acceptable attire for all meetings.

<u>Major Meeting Objectives</u>:

- To be informed about Work Group decisions/closure and formulate recommendations to EPA, if appropriate:

    - Incinerator Work Group - Regulatory Alternatives Paper
    - Boiler Work Group - MACT Floor for Natural Gas and Oil
    - Boiler Work Group - HAPs of Interest for Fossil Fuel
    - Turbine Work Group - Cost Effectiveness of Emission Control
    - Testing and Monitoring Protocol Work Group - Interpreting Non-Detect Emission Measurements
    - Engine Work Group - Rich Burn Engine Definition
    - Engine Work Group - Assessment of Emission Database
    - Engine Work Group - MACT for Digester and Landfill Gas Combustion

- To be informed about Work Group Works-in-Progress and Data/Information Items and forward these to EPA.

Location of Documents on the TTN for Downloading

Closure Items

The following closure items are posted on the TTN's CC Pre-Meeting Review Documents page.

Work Group	Closure Item	Filename
Incinerators	Regulatory Alternatives Paper (RAP)	Rap-v5.pdf/.wpd
Boilers	MACT Floor for Natural Gas and Fuel Oil Boilers	mactfnl5.pdf; mactfin4.pdf
Boilers	HAPs of Interest for Fossil Fuel Fired Boilers	fhapsfl3.pdf; fhap0916.pdf
Turbines	Cost Effectiveness of HAP Emissions Control	costeff.pdf
Testing and Monitoring Protocol	Interpreting and Using Emission Databases Containing Non-Detection Values	tmdetect.pdf/.wpd
Engines	Rich Burn Engine Definition	rb97rice.pdf
Engines	Assessment of RICE Emissions Database	em97rice.pdf
Engines	Above the Floor MACT for Digester and Landfill Gas	wpmact1.pdf

Works-In-Progress

Except as noted in the Filename column, the following works-in-progress are posted on the TTN's CC Pre-Meeting Review Documents page.

Work Group	Work-in-Progress Item	Filename
Turbines	Considerations for Gas-Fired Combustion Turbines MACT	gaswhit2.pdf
Turbines	Model Turbines and Control Alternatives Cost Analyses for Existing and New Sources	Hardcopy will be on display at CC meeting
Turbines	CTWG Pollution Prevention Considerations	p2memo.pdf
Turbines	Subcategorization Report	sub_tran.pdf/.wpd
Turbines	HAPs vs. Criteria Pollutants Report	hvc_tran.pdf/.wpd
Turbines	Preliminary Results from Natural Gas-Fired CT Testing	api_gri.pdf
Engines	Pollution Prevention for RICE	p2engine.pdf
Engines	Definitions	definit5.pdf/.wpd
Engines	Cost of Control Catalysts	costsub3.pdf/.wpd
Engines	New Source MACT for RICE	nsmact.pdf
Boilers	Control Technology Rankings	boilctr.pdf
Boilers	Economics Task Group Analyses	boiletga.pdf
Boilers	Subcategories for Boilers Firing Wood, Non-Fossil Materials and Coal	bosubcat.pdf/.wpd
Boilers	Model Boilers for Boilers Firing Wood, Fossil and Non-Fossil Materials	bomodel.pdf
Boilers	HAPs of Interest for Wood-Fired Boilers and Digester Gas Fired Boilers	boilhaps.pdf; attachments on display at CC meeting
Boilers	Preliminary MACT Floor Analyses for Wood and Non-Fossil Boilers	boilprmt.pdf
Boilers	Good Combustion Practices Required by State Rules	boilagcp.pdf
Boilers	De Minimus Levels for Boilers Subject to Section 129	129demin.pdf/.wpd
Process Heaters	Rationale for Determination of MACT for Indirect-Fired Process Heaters	mactdoc.pdf/.wpd; mactdocf.pdf
Process Heaters	White Paper on Coke Oven Gas	* Process Heaters, Misc files, cogfinal.pdf/.wpd, 8/5/98
Process Heaters	Status Report on "Other-Fired" Indirect Process Heaters	othersum.pdf/.wpd
Process Heaters	Flow-chart of Indirect-Fired Process Heaters	dbflow2.pdf
Process Heaters	Process Heater Database Analysis of Controlled Units	Hardcopy will be on display at CC meeting

Work Group	Work-in-Progress Item	Filename
General ICCR	CC Guidance to Work Groups on Operator Training	* CC Miscellaneous Files, 5/12/98, p2optrn.pdf/.wpd
General ICCR	CC Guidance to Work Groups on Pollution Prevention Metrics	* CC Miscellaneous Files, 5/12/98, p2metric.pdf/.wpd
General ICCR	CC Guidance to Work Groups on Pollution Prevention Regulatory Approaches	* CC Miscellaneous Files, 5/12/98, p2regopt.pdf/.wpd
General ICCR	Good Combustion Practice Guidance	* CC Miscellaneous Files, 3/20/98, gcp.pdf/.wpd
General ICCR	Pollution Prevention Subgroup Report on Fuel/Waste Constituent Levels and Fuel/Waste De Minimus Constituent Levels	* CC Miscellaneous Files, 5/18/98, p2subgr.pdf/.wpd

* These items were previously posted on the TTN.

Data/Information Items Available on the TTN

Most of these data files were previously posted and are located on the Work Group boards or on the General Information board. The locations and filenames are shown below.

Work Group	Data/Information Item	Location	Filename, Date
Turbines	Refined Inventory Database	Turbines board, Misc files	ct-sslof.exe, dbs_tran.pdf/.wpd
Turbines	Emissions Database	Turbines board, Misc files	etd3_ct.exe, dbs_tran.pdf/.wpd
Engines	Emissions Database	RICE board, Misc files	etd2_ice.zip, 3/16/98
Engines	Inventory/Population Database	RICE board, Misc files	sslof28.exe
Engines	Federal Units Population Estimates	RICE board, Misc files	ricefedu.pdf
Boilers	Corrections Made to Inventory Database	Boilers board, Misc files	boilerv4.exe
Process Heaters	Refined Inventory Database	Process Heaters board, Misc files	phrefind.exe
Process Heaters	Emissions Database	Process Heaters board, Misc files	etdphv3.exe, 4/28/98
Process Heaters	Survey Database	General Info board, Info Collection Area	surveyv2.exe, 3/13/98
Testing and Monitoring Protocol	A Review of Formaldehyde Measurements by the DNPH Methods	TMP board, Misc files	formald1.pdf/.wpd, 7/14/97
Testing and Monitoring Protocol	Discussion of Real Time Measurement Options to IC Engine WG	TMP board, Misc files	tmrealtm.pdf/.wpd, 9/5/97
Testing and Monitoring Protocol	Typical Products of Incomplete Combustion (PICs) that are also HAPs	TMP board, Misc files	tmpicgd.pdf/.wpd, 11/7/97
Testing and Monitoring Protocol	Review of Compliance Test Methods for Determining Formaldehyde Emissions from IC Engines and Turbines	TMP board, Misc file	formald2.pdf/.wpd
General ICCR	Dioxin Primer Presentation	CC board, Archived old files	dioxinpr.pdf, 1/6/98
General ICCR	ICR Survey Database Version 2.0	General Info board, Info Collection area	surveyv2.exe, 3/13/98
General ICCR	Inventory Database Version 3.0 and Associated Documentation Tables	General Info board, Info Collection area	iccrv3.exe, 3/12/98; iccrref.exe, 2/19/98; iccrdel.exe, 2/19/98; source.xls, 4/30/97

Work Group	Data/Information Item	Location	Filename, Date
General ICCR	Additional Inventory Data from DoD	General Info board, Info Collection area	dod3.exe
General ICCR	Additional Inventory and Survey Data from AMSA	General Info board, Info Collection area	amsa_inv.exe; amsa_sur.exe
General ICCR	Emission Test Database versions 2.0 and 3.0 for combustion turbines	CT board, Misc files	etd2_ct7.zip, 2/5/98; etd_ct.zip, 1/8/98; etd3_ct.exe
General ICCR	RICE Emissions Database version 2.0	RICE board, Misc files	etd2_ice.zip,3/16/98; etd_ice7.zip, 3/16/98
General ICCR	Supplements to Boilers Emissions Test Database, versions 4.1, 4.2 and 4.3	Boilers board, Misc files	finblr42.exe, 8/6/98; finblr41.exe, 6/30/98
General ICCR	Emission Test Database version 3.0 - Boilers	Boilers board, Misc files	etdblrv3.exe, 4/28/98
General ICCR	Emissions Test Database version 3.0 - Process Heaters	Process Heaters board, Misc files	etdphv3.exe, 4/28/98
General ICCR	Supplements to Incinerators Emission Test Database, versions 4.1, 4.2 and 4.3	Incinerators board, Misc files	fininc42.exe, 8/6/98; fininc41.exe, 6/30/98
General ICCR	Emission Test Database version 3.0 - Incinerators and Flares	Incinerators board, Misc files	etdincv3.exe, 4/28/98
General ICCR	Materials Analysis Database version 1.0	General Info board, Info Collection area	matv1.exe, 8/28/98
General ICCR	CC and Subgroup Meeting Minutes	CC board, Minutes of Previous Meetings page	
General ICCR	WG and Subgroup Meeting Minutes	WG boards, Minutes of Previous Meetings pages	
General ICCR	Information Collection Plan and Survey Recommendations from CC to EPA	CC board, Archived old files	cc19ma7l.pdf, 1/6/98 (see sec 3.2 and attachments 4 & 5)

Data/Information Items Not Available on the TTN

The following items are not available electronically. A hardcopy will be on display at the meeting.

Work Group	Data/Information Item
Turbines	HAP Technology Workshop Documents
Boilers	State Regulations on Boilers
Boilers	Material Analyses Information not Included in Materials Analysis Database
Boilers	Results of Literature Search Conducted by Boiler Testing Task Group
Incinerators	Operating Non-hazardous Solid Waste Incinerators
Incinerators	Development of IWG Subteam #1 Facility List
Incinerators	Development of IWG Subteam #2 Facility List
Incinerators	Procedure/Documentation, Subteam #3
Incinerators	Development of the IWG Subteam #4 Database
Incinerators	Environmental Threats to Children, memorandum
Incinerators	Environmental Threats to Children, letter

Wednesday, September 16 — Work Group Closure Items

8:00 am	Welcome and Agenda Review
8:10 am	General Business and EPA Feedback
8:30 am	Incineration Work Group Closure Presentation and Committee Discussion • Regulatory Alternatives Paper
9:00 am	Public Comment and Opportunity to Exchange Ideas with the Committee
9:10 am	Committee Closure and Formulation of Recommendations to EPA, If Appropriate
9:30 am	Boiler Work Group Closure Presentation and Committee Discussion • MACT Floor for Natural Gas and Oil
10:00 am	Public Comment and Opportunity to Exchange Ideas with the Committee
10:10 am	Break
10:25 am	Committee Closure and Formulation of Recommendations to EPA, If Appropriate
10:45 am	Boiler Work Group Closure Presentation and Committee Discussion • HAPs of Interest for Fossil Fuels
11:15 am	Public Comment and Opportunity to Exchange Ideas with the Committee
11:25 am	Committee Closure and Formulation of Recommendations to EPA, If Appropriate
11:45 am	Turbines Work Group Closure Presentation and Committee Discussion • Cost Effectiveness of Emission Control
12:15 pm	Public Comment and Opportunity to Exchange Ideas with the Committee
12:25 pm	Committee Closure and Formulation of Recommendations to EPA, If Appropriate
12:45 pm	Lunch
1:45 pm	Testing and Monitoring Protocol Work Group Closure Presentation and Committee Discussion • Interpreting Non-Detect Emission Measurements
2:15 pm	Public Comment and Opportunity to Exchange Ideas with the Committee
2:25 pm	Committee Closure and Formulation of Recommendations to EPA, If Appropriate

2:45 pm	Engines Work Group Closure Presentation and Committee Discussion • Definition of Rich Burn Engines
3:15 pm	Public Comment and Opportunity to Exchange Ideas with the Committee
3:25 pm	Break
3:40 pm	Committee Closure and Formulation of Recommendations to EPA, If Appropriate
4:00 pm	Engines Work Group Closure Presentation and Committee Discussion • Assessment of Emissions Database
4:30 pm	Public Comment and Opportunity to Exchange Ideas with the Committee
4:40 pm	Committee Closure and Formulation of Recommendations to EPA, If Appropriate
5:00 pm	Engines Work Group Closure Presentation and Committee Discussion • MACT for Digester and Landfill Gas Combustion
5:30 pm	Public Comment and Opportunity to Exchange Ideas with the Committee
5:40 pm	Committee Closure and Formulation of Recommendations to EPA, If Appropriate
6:00 pm	Review Goals and Agenda for Tomorrow's Meeting
6:10 pm	Adjourn

Thursday, September 17 — Work Group Works-in-Progress & Data/Information

8:00 am	Agenda Review / Goals for the Day
8:10 am	Dioxin Primer - Overview Presentation
8:15 am	Pollution Prevention Subgroup - Overview Presentation
8:25 am	Public Comment and Opportunity to Exchange Ideas with the Committee
8:35 am	Committee Discussion
8:50 am	Incinerator Work Group - Overview Presentation
9:00 am	Public Comment and Opportunity to Exchange Ideas with the Committee
9:05 am	Committee Discussion
9:15 am	Turbine Work Group - Overview Presentation
9:45 am	Public Comment and Opportunity to Exchange Ideas with the Committee
9:55 am	Committee Discussion
10:25 am	Break
10:40 am	Engine Work Group - Overview Presentation
11:00 am	Public Comment and Opportunity to Exchange Ideas with the Committee
11:10 am	Committee Discussion
11:30 am	Process Heater Work Group - Overview Presentation
11:50 am	Public Comment and Opportunity to Exchange Ideas with the Committee
12:00 pm	Committee Discussion
12:20 pm	Lunch
1:20 pm	Boiler Work Group - Overview Presentation
2:00 pm	Public Comment and Opportunity to Exchange Ideas with the Committee
2:10 pm	Committee Discussion

2:50 pm	Break
3:05 pm	Testing and Monitoring Protocol Workgroup - Overview Presentation
3:15 pm	Public Comment and Opportunity to Exchange Ideas with the Committee
3:20 pm	Committee Discussion
3:30 pm	Forward all Work Group Works-in-Progress & Data/Information Items to EPA
3:35 pm	Environmental Caucus - Environmental Justice Discussion
3:55 pm	Public Comment and Opportunity to Exchange Ideas with the Committee
4:10 pm	Committee Discussion and Formulation of Recommendations to EPA, If Appropriate
4:40 pm	Review and Approve Flash Minutes
5:00 pm	Adjourn

Attachment 3

Flash Minutes of September 16 & 17, 1998, Coordinating Committee Meeting

INDUSTRIAL COMBUSTION COORDINATED RULEMAKING (ICCR) COORDINATING COMMITTEE MEETING

SEPTEMBER 16-17, 1998
DURHAM, NORTH CAROLINA

DISCUSSION AND DECISIONS

- Fred Porter of EPA provided brief updates on EPA's consideration of previous Coordinating Committee (CC) recommendations.

- The CC reached consensus to forward the Section 129 regulatory alternatives paper (RAP) to EPA as a CC recommendation.

- The CC reached consensus to forward the report on preliminary MACT floor determinations for gas- and oil-fired boilers to EPA as a CC recommendation. Five wording changes suggested by the Boilers Work Group will be made to the document.

- The CC reached consensus to forward the paper on hazardous air pollutants (HAPs) of interest for fossil fuel-fired boilers to EPA as a CC recommendation.

- The CC reached consensus to forward the paper on oxidation catalyst control for turbines to EPA. The transmittal letter will characterize the report as a "cost analysis". The transmittal letter will also refer to the full meeting minutes for a summary of CC discussion on the paper.

- The CC reached consensus to forward the document on using databases containing non-detection values to EPA as a CC recommendation. The full minutes will summarize additional CC discussion.

- The CC reached consensus to forward the paper on the definition of rich burn engines to EPA as a CC recommendation. A member stressed the importance of consistency between the definition and the subcategory analysis.

- The CC reached consensus to forward the paper on the assessment of the emissions database for reciprocating internal combustion engines (RICE) to EPA as a CC recommendation.

- The CC reached consensus to forward the paper on above-the-floor technologies for digester and landfill gas RICE to EPA as a CC recommendation. One wording change was agreed upon. The transmittal letter will also refer to the full meeting minutes for additional CC discussion.

- The CC discussed options for procedures to transmit work-in-progress to EPA. The CC agreed upon the following transmittal language for a cover memo for the works-in-progress and on footer language for a footer that will go on each page of each work-in-progress document.

  Cover Memo:
  "The CC forwards the following Work Group works-in-progress to U.S. EPA for appropriate consideration, not as recommendations, consistent with the discussion at its July 1998 Coordinating Committee meeting (see minutes, p. 4-5). Statements in these documents may not represent the opinions of all Coordinating Committee members. Works-in-progress include draft and incomplete items on which the CC has not reached closure. These items have only as much weight as individual comments EPA receives from any individual."

  Footer for each page:
  "This document is a Work Group work-in-progress forwarded to U.S. EPA by the ICCR Advisory Committee. The Advisory Committee did not reach closure on this document prior to the Advisory Committee's termination. Consequently, nothing herein constitutes a recommendation from the Advisory Committee and individual members of the Committee may not agree with all of the statements herein."

- The works-in-progress will not be edited. Any person can send EPA comments on any of the work-in-progress or data/information items.

- The CC reached consensus to transmit all of the data/information items (listed on pages 5 through 7 of the Agenda) to EPA for consideration using the agreed upon transmittal language and footer.

- The CC reached consensus to transmit all of the works-in-progress (listed on pages 3 and 4 of the Agenda) to EPA for consideration using the agreed upon transmittal language and footer.

- Several CC members made comments for the record on individual works-in-progress. These will be documented in the full meeting minutes for EPA's consideration.

- The Environmental Caucus presented an environmental justice (EJ) proposal. The CC reached consensus to transmit the Environmental Caucus EJ proposal to EPA for consideration using the following transmittal language: "The CC transmits the Environmental Caucus EJ proposal, background material, and the minutes from the CC discussions about this topic at the July and September meetings to EPA for consideration."

  The same footer will be put on each page as the other works-in-progress, except the words "Work Group" will be changed to "Environmental Caucus" in this footer.

Attachment 4

Regulatory Alternatives Paper
(Closure Item)

REGULATORY ALTERNATIVES PAPER

Prepared by:

The Incinerator Work Group

Submitted to:

ICCR Coordinating Committee
Research Triangle Park, North Carolina

September 8, 1998

PREFACE

This Regulatory Alternatives Paper (RAP) has been prepared by the Incinerator Work Group (IWG) for presentation to the ICCR Coordinating Committee (CC) at its September 16-17, 1998, meeting in Research Triangle Park, North Carolina. While it would be unrealistic to expect every IWG member to agree with every detail in a complex document such as this, the IWG concurs with the overall content and focus of the RAP and has reached consensus on submitting it to the CC as a final report. Note that the Boiler Work Group has collaborated with the IWG on some sections of the RAP and has provided preliminary information related to certain source categories (i.e., potential Section 129 solid mixed feed boilers and liquid mixed feed boilers).

Members of the Incinerator Work Group
September 8, 1998

Ethan Begg	*George Parris*
Beth Berglund	*Bill Perdue*
Rick Crume	*Paul Rahill*
Jon Devine	*Dale Walter*
Brian Dittberner	*Edward Repa*
Lawrence Doucet	*Andrew Roth*
Wayne Elliott	*Patricia Rykowski*
Larry Faith	*Dana Worcester*
Doug Finan	*Jeffrey Shumaker*
Anthony Licata	*Paul Tucker*
Dave Maddox	*Larry Thompson*
Ruth Mahr	*Tom Tyler*
Dennis Marietta	*Dick Van Frank*
David Marrack	*Ed Wheless*
Robert Morris	*Brian Guzzone*
Norman Morrow	*William Wiley*

ERG Contractor Assistance:

Susan Radomski	*Tom Waddell*
Chris Sarsony	*Scott Warner*

TABLE OF CONTENTS

Figures and Tables

REGULATORY ALTERNATIVES PAPER

1.0 INTRODUCTION

The Incinerator Work Group (IWG) of the Industrial Combustion Coordinated Rulemaking (ICCR) has prepared this Regulatory Alternatives Paper (RAP) for review by the ICCR Coordinating Committee (CC). The IWG recommends that the CC adopt this RAP as Committee recommendations to EPA for consideration in preparing a summary of regulatory alternatives, which the Agency must submit to litigants pursuant to a consent decree involving industrial and commercial waste incinerators. EPA's summary of regulatory alternatives is due to the litigants on November 16, 1998.

The RAP is an intermediate product in the regulatory development process. It contains recommendations regarding categories of *nonhazardous solid waste incinerators* considered for regulation under section 129 of the *Clean Air Act*, the pollutants to be regulated, and potential control alternatives for each incinerator subcategory. Additionally, the RAP contains other relevant subcategory-specific information such as subcategory population statistics, combustion device descriptions, the status of data collection and analysis, and issues and needs. The information and recommendations presented in the RAP are preliminary and will continue to evolve throughout the regulatory development process.

The ICCR CC is chartered under the Federal Advisory Committee Act (FACA). As such, the work of the CC and the ICCR's seven Work Groups is conducted by *stakeholders* representing industries, environmental groups, State and local agencies, and other interested parties. The ICCR's five source Work Groups address incinerators, boilers, process heaters, gas turbines, and internal combustion engines. These source Work Groups are supported by two additional Work Groups responsible for testing/monitoring and economics. All seven Work Groups and their organizational relationship to the CC are illustrated in Figure 1. Although the IWG has taken the lead in preparing this RAP, the Boiler Work Group (BWG) has collaborated with the IWG on some sections of the RAP and has provided information related to certain source categories. Because the ICCR's FACA charter expires in September 1998, the RAP will be the IWG's final report.

This paper is organized into sections on background, applicability, subcategory characterizations and regulatory alternatives, pollution prevention, statutes and executive orders, and issues and needs. Additionally, draft applicability language and definition sheets for the emission source subcategories identified by the IWG and BWG to date are attached.[1]

2.0 BACKGROUND

[1]Depending on the final definition of solid waste, it is possible that some process heaters could be subject to Section 129. However, because the applicability of Section 129 to process heaters is still unclear and because only a few such units could ultimately fall under Section 129, process heaters are not covered in this document.

One mission of the ICCR source Work Groups is to develop information for consideration by the CC in developing recommendations to EPA regarding the development of nonhazardous solid waste incineration regulations under Section 129 of the *Clean Air Act*. In this effort, the IWG has been following an overall strategy that is illustrated in Figure 2, and the BWG has followed a similar strategy. Beginning with a well defined focus, schedule, and approach, the IWG analyzed the ICCR databases, developed scoping recommendations for new and existing combustion units within an overall regulatory framework, identified emission source subcategories, and prepared floor and control option recommendations. With input from the BWG, and considering the need to address Section 129 and other pollutants, the IWG prepared the RAP. (The steps beyond the RAP in Figure 2 will be addressed by EPA after the FACA's expiration.)

Much of the IWG's work has been conducted by subteams composed of Work Group members. The IWG's four subteams and source category responsibilities are listed in Table 1. The subteams initially concentrated on reviewing and updating the ICCR databases for incineration units. As part of this effort, the subteams confirmed that units are correctly listed as incinerators in the databases. Additionally, erroneous information such as incorrectly listed unit designs, operating parameters, and waste types was corrected, and units no longer in operation were identified. More recently, the subteams have developed the recommendations for subcategory definitions, emission floors, and control options that are presented in this RAP. The standard procedure has been for the subteams' work to be considered, commented on, and approved by the entire IWG before being forwarded as recommendations to the CC.

Because EPA has indicated that boilers and process heaters that combust nonhazardous solid waste should be considered "solid waste incineration units" under Section 129, the BWG has provided preliminary placeholder subcategories, and appropriate Process Heater Work Group (PHWG) subcategories may be added. However, the number and description of BWG and PHWG subcategories that may ultimately be addressed under Section 129 remains uncertain at this time, in part because the Agency has yet to adopt a definition of nonhazardous solid waste for use in Section 129 regulations.[2] This definition of nonhazardous solid waste is crucial to determining whether certain combustion units will ultimately be considered nonhazardous solid waste incineration units subject to Section 129 or combustion units subject to Section 112. The definition of nonhazardous solid waste is not as crucial to the IWG and this RAP because all nonhazardous waste incinerators are considered by EPA to be subject to Section 129 regardless of the materials combusted. It should be noted that incinerators, boilers, and process heaters have distinctively different functions. Whereas the primary purpose of an incinerator is to reduce the volume of waste, the primary purpose of a boiler is to produce useful steam or hot water, and process heaters are designed to transfer useful heat to an industrial or commercial process.

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[2]At its November 18-19, 1997, meeting, the CC forwarded to EPA recommendations and accompanying stakeholder position papers on the definition of nonhazardous solid waste. These documents are attached to the November 18-19 meeting minutes on the ICCR Internet web page at http://www.epa.gov/ttn/iccr/cdira.html. On June 5, 1998, EPA staff issued a draft definition of nonhazardous solid waste, for purposes of the ICCR, as guidance to the Work Groups.

The IWG has identified the following five nonhazardous solid waste incineration subcategories for possible regulation under Section 129:

- **Miscellaneous Industrial and Commercial Waste Incinerators**
- **Wood and wood waste incinerators** -- *including separate groupings for milled solid and engineered wood; harvested wood and agricultural waste; and construction, demolition, and treated wood wastes.*
- **Pathological waste incinerators and crematories** -- *including separate groupings based on feed rate for poultry farms; human crematories; and hospital, animal control, and research facilities.*
- **Drum reclaimer furnaces**
- **Parts reclaimer burnoff units**

Additionally the BWG, in cooperation with the IWG, has identified the following placeholder subcategories, subject to further analysis by the BWG and a final definition of nonhazardous solid waste:

- **Potential Section 129 solid mixed feed boilers**
- **Potential Section 129 liquid mixed feed boilers**

Section 129 addresses four categories of incineration units -- municipal solid waste (MSW) combustors, hospital and medical infectious waste (HMIW) incinerators, industrial and commercial waste incinerators (ICWI), and other solid waste incinerators (OSWI). Rules addressing the first two categories have been promulgated. However, rule applicability excludes units combusting less than 250 tons per day (tpd) of municipal solid waste (determined by weight on a quarterly average basis), larger units combusting less than 30% municipal solid waste, and units burning less than 10% hospital and medical infectious wastes. EPA has decided to address the <250 tpd municipal solid waste units outside of the ICCR. The <30% municipal solid waste and <10% hospital and medical infectious waste incineration units are included in the ICCR and will be addressed in one of the subcategories ultimately established for the Section 129 rulemaking.

The IWG recommends a separate set of regulatory requirements (e.g., emission limits) for each of the above subcategories and groupings. However, EPA may want to consider a further subdividing or combining of these subcategories and groupings as additional information is received and analyzed. Additionally, as new information is received, it may be necessary to create a *miscellaneous* or *other* category to ensure that any units not covered by the above subcategories are addressed.

EPA has indicated that Section 129 addresses incinerator units and other combustor units burning nonhazardous solid waste. The currently identified subcategories are believed to provide comprehensive coverage, with the Miscellaneous Industrial and Commercial Waste Incineration category believed to include the mixed feed and industrial solid waste incineration units not included in any of the other IWG subcategories. However, should that not prove to be the case, the Miscellaneous Industrial and Commercial Waste Incineration category could be expanded to include units not covered, or a new miscellaneous category could be defined. To date, all incinerators in the ICCR's databases that have been determined to be the responsibility of the ICCR are assigned to one of the IWG subcategories. Thus, it is unclear whether an additional *miscellaneous* or *other* category will ultimately be necessary.

The IWG recommends that the regulatory requirements for the above nonhazardous solid waste incineration subcategories be addressed in a single rulemaking package (i.e., a single preamble and regulation for proposal, and the same for promulgation) for efficiency purposes and because many of the requirements (e.g., for monitoring, recordkeeping, reporting, operator training and certification, siting, and pollution prevention) may be the same across multiple subcategories. We believe that this approach will simplify the rulemaking process, thereby fostering understanding of the regulatory requirements and better compliance. Because Section 129 distinguishes between ICWI and OSWI, EPA has indicated that the rulemaking package would need to distinguish between these two categories of combustion units. Although the November 16, 1998, consent decree only requires EPA to discuss regulatory alternatives for ICWI sources, OSWI sources are also discussed in this RAP due to their similarity and because we recommend that EPA develop a combined ICWI/OSWI regulation.

Much of the ICCR Work Groups' past work has been devoted to analyzing data contained in the following three databases:

- **Inventory database** -- *a detailed listing of industrial and commercial combustion units used by all five ICCR source Work Groups and derived from existing State and federal databases.*

- **Information collection request (ICR)/survey database** -- *responses from a recent survey providing updated and detailed information for facilities identified in the inventory database as combusting nonhazardous solid waste.*

- **Emissions database** -- *emissions data collected from State agencies representing source testing of a variety of combustion units.*

The ICCR inventory database contains 8,091 facilities believed to have one or more incineration units. However, the responses to the ICR indicate that many of these units have been shut down or otherwise do not exist. (This may reflect the substantial progress made by industry in recent years to reduce the amount of waste produced.) Other units were eliminated from consideration because they were determined to be burning hospital and infectious medical waste, municipal waste, or other types of materials outside the scope of the ICCR. The status of about 1,700 potential units remains unknown because of insufficient information. Taking all of these factors into consideration, our best estimate of the number of incineration units in the inventory and ICR databases that are currently in operation and being addressed by the IWG is about 1,600.

This estimate could increase or decrease by several hundred units as more information becomes available (e.g., the results of a follow-up mailing to facilities not responding to the first mailing).

The extent to which the inventory and ICR databases capture all operating incinerators in the U.S. is unknown. However, based on population estimates for individual subcategories, a rough guess is that the inventory and ICR databases represent most of the wood, wood waste, and drum and parts reclaimer units currently operating in the U.S. and over 50% of the remaining incineration subcategories, with the exception of several thousand poultry farm incinerators. These poultry farm units, typically rated at <100 lb/hr, have probably never been regulated or permitted due to their small size. (Information on these units was obtained from equipment manufacturers.) In summary, although not all incineration units are captured within our databases, the IWG believes that the databases are representative of the cross-section of U.S. incinerators and provide a basis for rulemaking.

3.0 APPLICABILITY

The recommendations presented in this RAP will apply to all incineration units that are not exempt from Section 129 or addressed by other rulemakings. Section 129(g)(l) exempts wastes required to have a permit under Section 3005 of the Solid Waste Disposal Act (i.e., hazardous wastes), material recovery facilities which combust waste for the primary purpose of recovering metals, qualifying small power production and co-generation facilities, and air curtain incinerators combusting only yard and wood wastes and clean lumber. Additionally, municipal waste combustors and hospital and medical infectious waste incinerators are exempt from this rulemaking because they are being addressed by EPA in parallel rulemakings or because they are already covered by other rulemakings. An example of draft applicability language and definitions for a combined ICWI/OSWI rule are presented in Attachment A.

4.0 SUBCATEGORY CHARACTERIZATIONS AND REGULATORY ALTERNATIVES

Descriptions of each recommended subcategory are presented in Attachment B and summarized in Table 2. Additionally, information and recommendations are presented on pollutants considered for regulation (at a minimum the nine pollutants listed in Section 129), whether a subcategory falls under ICWI or OSWI, any groupings within the subcategory, population statistics, material combusted, combustion device description, the basis for subcategory bounds, the floor level of control, the status of data collection and analysis, issues and needs, and other comments.

Based on the information currently available to the IWG, it appears that most existing incineration units have minimal or no controls in place. The exception is for most drum reclaimer furnaces and parts reclaimer burnoff ovens, which appear to have thermal oxidizers. Additionally, good combustion practices are routinely applied to pathological units due to State regulations. Only very limited test data on most pollutants of interest are available for all incinerator subcategories, and the IWG, with the assistance of the BWG, has recommended test programs to address these data needs. Some subcategories (e.g., wood wastes) are small in terms of the number of operating units, and these may be candidates for merging into a larger subcategory, provided that unit designs, emissions, and controls are similar. For the two preliminary subcategories defined by the BWG, several floor controls and options above the floor have been identified.

5.0 POLLUTION PREVENTION

The IWG believes that pollution prevention should be considered an integral part of the Section 129 rulemaking and is committed to a further investigation of the feasibility, practicality, and cost-effectiveness of various pollution prevention techniques. This commitment is consistent with the goals of the *Pollution Prevention Act of 1990* and EPA policy to consider and facilitate the adoption of source reduction techniques. Additionally, EPA has stated its opinion that Section 129(a)(3) of the *Clean Air Act* anticipates that pollution prevention may be included in regulations (i.e., as the basis of a floor or control level above the floor) by stating that standards "... shall be based on methods and technologies for the *removal* or destruction of pollutants *before*, during, or after combustion ... [emphasis added]." Thus, pollution prevention allows sources, in meeting numeric emissions limits, to choose pollution prevention measures as alternatives to add-on pollution control devices.

Discussed below are several specific pollution prevention approaches forwarded by the CC to the Work Groups for their consideration.

<u>Good combustion practices</u>. The CC has prepared guidance for the source Work Groups to consider on GCP options. The good combustion techniques covered in this guidance include:

- Operator practices
- Maintenance knowledge and practices
- Stoichiometric ratio (air/fuel)
- Firebox residence time, temperature, and turbulence
- Fuel/waste quality, handling, sizing, dispersion, and liquid atomization
- Combustion air distribution

If appropriate, implementation of these techniques could be accomplished through a combination of documented operating and maintenance procedures, logs and record-keeping, training on equipment and procedures, routinely scheduled inspections and maintenance, burner and control adjustments, system design, fuel/waste monitoring, and various system adjustments. (Although operator training itself could also be considered a good combustion practice, it is covered separately below.) The IWG believes that these techniques are potentially applicable to incineration units under Section 129, but the Work Group has not studied the specific applicability, benefit, disbenefit, or cost effectiveness of these techniques.

The IWG believes that practical and effective combustion practices may be applicable to some of its subcategories. Because of the variety of unit designs and waste types being addressed, it may be appropriate to develop a separate set of GCPs for each subcategory. For some subcategories, no GCPs may be appropriate. On the other hand, if there are practical and effective combustion practices that are the same or similar among multiple subcategories, a single set of GCPs for all units covered by those subcategories may be considered.

Operator Training/Qualification. Section 129(d) requires EPA to "... develop and promote a model State program for the training and certification of solid waste incineration unit operators ..." The CC's list of training/qualification activities for Work Group consideration includes the following definition of "operator:"

- # Operator means an individual or individuals whose work duties include the operation, evaluation, and/or adjustment of the combustion system.

The IWG supports this definition, although additional specificity will be needed to distinguish unit "operators" from mechanics, engineers, and others who may occasionally evaluate or adjust the combustion system. A clear distinction will have to be made between the incinerator "operator' and the "owner/operator" of the unit or facility.

The CC's initial list of potential pollution prevention approaches for consideration includes specific training program elements, including:

- # Training and qualification criteria
- # Training programs and qualification exams
- # Training program materials and documentation of qualification

The IWG considers these requirements reasonable for some incinerator operators, although details will need to be worked out. As outlined in the Pollution Prevention subgroup's recommendations, each facility would develop an operator training and testing program tailored to their equipment and site.

Metrics. Emission limits previously promulgated under Section 129 (i.e., the municipal waste and hospital and medical infectious waste rules) have been expressed in units of concentration (e.g., *ng/dscm* or *ppm*). Concentration units are effective in reducing emissions based on control device efficiency and may also encourage pollution prevention. However, some pollution prevention techniques that significantly reduce mass emission rates may not concurrently reduce mass concentrations.

To encourage pollution prevention, the CC has asked the Work Groups to consider metrics other than concentration emission limits, where the numerator in the emission limit would be based on pollutant mass (e.g., *ng*) and the denominator would be based on time, energy output, heat input, fuel/waste input, or unit of production. However, compliance with such metrics may be impractical where the metrics are combustion unit size/capacity specific (e.g., metrics based on time), difficult to measure (e.g., metrics based on energy output, heat input, or fuel/waste input), or difficult to quantify (e.g., metrics based on unit of production). The IWG believes that the concept of metrics has merit, but that additional study is needed to determine whether this approach is practical or appropriate for compliance and effective in reducing emissions from Section 129 incineration units.

Regulatory Options. The CC has also recommended considering regulatory options such as waste accounting and recordkeeping and work practice standards. Waste accounting and recordkeeping would provide a paper trail of waste feedstream composition, thereby highlighting opportunities for source separation, source elimination, or recycle/recovery. Work practice standards would require specific handling or separation procedures for waste materials prior to burning, thereby reducing undesirable materials (e.g., waste components leading to specific HAP emissions) and potentially improving combustion efficiency (e.g., by removing high moisture content materials from the waste steam).

The IWG considers these viable techniques in principle, although further information is needed on: (1) what specific handling or separation procedures might be applied to each of the subcategories, (2) the data or reasoning (e.g., based on combustion chemistry or engineering calculations) leading to the conclusion that a specific handling or separation procedure would provide a significant net life-cycle environmental benefit, and (3) evaluation of the potential benefit versus the burden (including economic burden) imposed.

6.0 STATUTES AND EXECUTIVE ORDERS

In addition to the substantive requirements imposed by the Clean Air Act when promulgating regulations, the Agency must comply with a number of administrative responsibilities prior to adopting regulations. Some of these obligations flow from statutes and others from executive orders (EOs) signed by the President as directives to the Executive Branch.

EPA must comply with administrative requirements in the following five statutes at the proposal stage of a regulation's development.[3]

- Section 307(d) of the *Clean Air Act* requires that regulations under Section 129 be supported by a rulemaking docket and allow for both written and oral comment upon the proposed rule.

- Under the *Paperwork Reduction Act*, EPA must obtain a control number from the Office of Management and Budget (OMB) if the regulation contains any information collection request (reporting obligations under an applicable emission standard, for instance) calling for answers to identical questions posed to ten or more persons.

- The *National Technology Transfer and Advancement Act (NTTAA)* mandates that EPA must use existing suitable voluntary consensus standards (e.g., test methods) unless their use would be inconsistent with applicable law or otherwise impractical in EPA's judgment.

- If the proposed regulation will contain a federal mandate forcing State, local, and tribal governments, in the aggregate, or the private sector to spend in excess of

[3]One additional statutory administrative requirement is triggered when the Agency promulgates *final* regulations. Under the Congressional Review Act, EPA generally must submit all rules of general applicability to Congress and the Comptroller General before the rule may take effect.

$100 million in any given year, the *Unfunded Mandates Reform Act (UMRA)* requires EPA to prepare a statement identifying a number of economic and environmental costs and benefits associated with the proposed rule, both locally and nationally. UMRA also requires that, for proposed rules which require an UMRA statement, EPA must identify and consider a reasonable number of regulatory alternatives and select the least costly, most cost-effective, or least burdensome option that is consistent with the agency's statutory duties, unless EPA explains its choice not to select one of the foregoing options. UMRA lastly contains two consultation requirements: (1) EPA must develop an effective process for consulting with elected officers of State, local, and tribal governments with regard to proposed rules that contain significant Federal intergovernmental mandates, and (2) it must develop a small government agency plan (which provides for notice to, input from, and education for, small governments regarding a proposed rule) for any rule that might significantly or uniquely affect small governments.

The *Regulatory Flexibility Act (RFA)*, as amended by the Small Business Regulatory Enforcement Fairness Act, requires EPA to prepare an initial regulatory flexibility analysis (IRFA), convene a small business advocacy review panel, and include the IRFA or a summary of it in the proposal's preamble, unless the Administrator can certify that a proposed regulation will not have a significant economic impact on a substantial number of small entities. (Additionally, Section 507 of the Act requires EPA and the States to develop small business stationary source technical and environmental compliance assistance programs.)

In addition to its statutory obligations, EPA has the following four EOs to consider.

Under *EO 12875, Enhancing the Intergovernmental Partnership*, EPA must develop an effective process for elected officials and other representatives of State, local, and tribal governments to provide meaningful and timely input on regulatory proposals containing significant unfunded mandates. Also, EPA may not (unless required by law) promulgate a regulation that creates an unfunded mandate upon State, local, or tribal governments without either providing funds necessary to pay the direct costs of compliance, or providing OMB a description of EPA's consultation with representatives of affected governments, the nature of their concerns, and EPA's position supporting the need for the regulation. (Congress subsequently enacted similar requirements in UMRA.) In some instances, EPA can waive regulatory requirements.

Under *EO 13084, Consultation and Coordination with Indian Tribal Governments*, EPA must establish an effective process permitting elected officials and other representatives of Tribal governments to provide meaningful and timely input into the development of regulatory policies for matters significantly or uniquely affecting their communities. In certain instances, the federal government must either fund compliance costs, or EPA must provide OMB a description of the extent of EPA's consultation with representatives of affected Tribal governments, the nature of their concerns, and EPA's position supporting the need for the regulation. In some instances, EPA can waive regulatory requirements. (These requirements are very similar to those in *EO 12875*.)

- Prior to proposal, *EO 12866* requires that EPA seek involvement of parties affected by a proposed rule and suggests that at least a 60 day comment period on proposed rules be offered. The same EO also requires that EPA submit to OMB any proposed or final *significant* regulatory action for interagency review.[4]

- *E.O. 12898* specifies that EPA must make achieving environmental justice part of its mission by identifying and addressing, as appropriate, practicable, and permitted by law, disproportionately high and adverse human health or environmental effects of its rulemaking actions on minority and low-income populations.[5]

The ICCR has laid the groundwork for developing recommendations aiding EPA's compliance with these obligations. Specifically, Work Groups have discussed recommendations for *model plants*, which will reflect the design of typical facilities in the affected industry and could be used when EPA seeks to conduct the economic and environmental analyses necessary to comply with UMRA, RFA, and *EO 12866.* The Agency could consider the effect of proposed regulations upon these model plants as illustrative of the impact the proposals may have nationally. In addition, ICCR Work Groups, in the course of recommending hazardous air pollutants (HAPs) for testing and regulation under Section 112, also have identified existing test methods for measuring HAPs, and recommendations that these existing test methods be considered for determining compliance with regulations could be useful to the Agency's compliance with the NTTAA's requirement to search for applicable voluntary consensus standards. Next, Section 129(a)(3) directs that standards for new sources incorporate "siting requirements that minimize, on a site specific basis, to the maximum extent practicable, potential

[4]*Significant* is defined as an action having an annual effect on the economy of $100 million or more; adversely affecting in any material way the economy, a sector of the economy, jobs, the environment, public health or safety, or affected governments or communities; creating a serious inconsistency or interfering with an action taken or planned by another agency; materially altering the budgetary impact of entitlements, grants, etc., or the rights/obligations of recipients; or raising novel legal or policy issues.

[5]If a rule is *significant* under *E.O. 12866* and it involves an environmental health or safety risk that EPA has reason to believe may disproportionately affect children, *EO 13045* requires EPA to evaluate the environmental health or safety effects of the planned regulation on children and explain why the proposal is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency. Since the standards to be developed under Section 129 are technology-based and not health- or risk-based, *EO 13045* does not apply to the determination of MACT floor. The IWG recommends that EPA consider whether and how *EO 13045* would otherwise influence the Work Group's other recommendations for MACT standard regulatory development (e.g., the selection of pollutants in addition to those listed in section 129(a)(4)).

risks to public health and the environment." Siting requirements may trigger environmental justice concerns.

7.0 ISSUES AND NEEDS

Waste Burning Boilers. Incinerators burning non-hazardous solid waste are covered under Section 129. However, there is an unresolved issue concerning boilers that burn waste or waste mixed with fuels (e.g. coal or natural gas). EPA's current opinion is that a boiler burning nonhazardous solid waste, as ultimately defined by EPA, is covered by Section 129. (See *footnote 2* regarding the status of the definition of nonhazardous solid waste.) Does this mean if the boiler burns any amount of waste that it is covered, or is there a minimum amount necessary before it falls under Section 129? In the case of incinerators that burn municipal solid waste (MSW), the unit falls under Section 129 if more than 30% MSW is combusted. However, in the case of boilers, the issue may be more complex since the composition and amount of waste burned may vary with time, and the toxicity of the emissions will also vary depending upon the composition of the waste stream. Since at present EPA has not finalized its definition of nonhazardous solid waste for the purposes of Section 129, should all materials disposed of by burning be addressed under Section 129?

Waste Composition Averaging Time. In many cases, incinerators and boilers burn waste streams that are not homogeneous. Depending upon the facility and wastes disposed of, waste "A" may be burned for several hours early in the work day, followed by waste "B," followed by wastes "C" and "D" or a mixture of A, B, C, and D in varying amounts. In some cases, waste "E" will be burned for several months, followed by waste "F" for some period of time. This may result in widely varying emissions over the course of a day, month, or year. Unless emissions testing is done when each waste is burned and in all possible combinations, emissions data will not be representative of actual operating conditions. Operating permits often specify a waste composition to be burned (e.g., % waste "X" per unit time), and long averaging times may result in periods of emissions of widely varying toxicities while still conforming to the conditions of the permit. Based on the above operating scenarios, an analysis of waste composition over time and resulting emissions is needed to define an acceptable averaging time for each subcategory. This analysis is necessary for purposes of determining the applicability of the standards, setting the level of the standards, and determining compliance. The heart of the issue is how averaging time impacts toxicity of emissions by allowing variability of mass emission rates while still assuring the protection of human health.

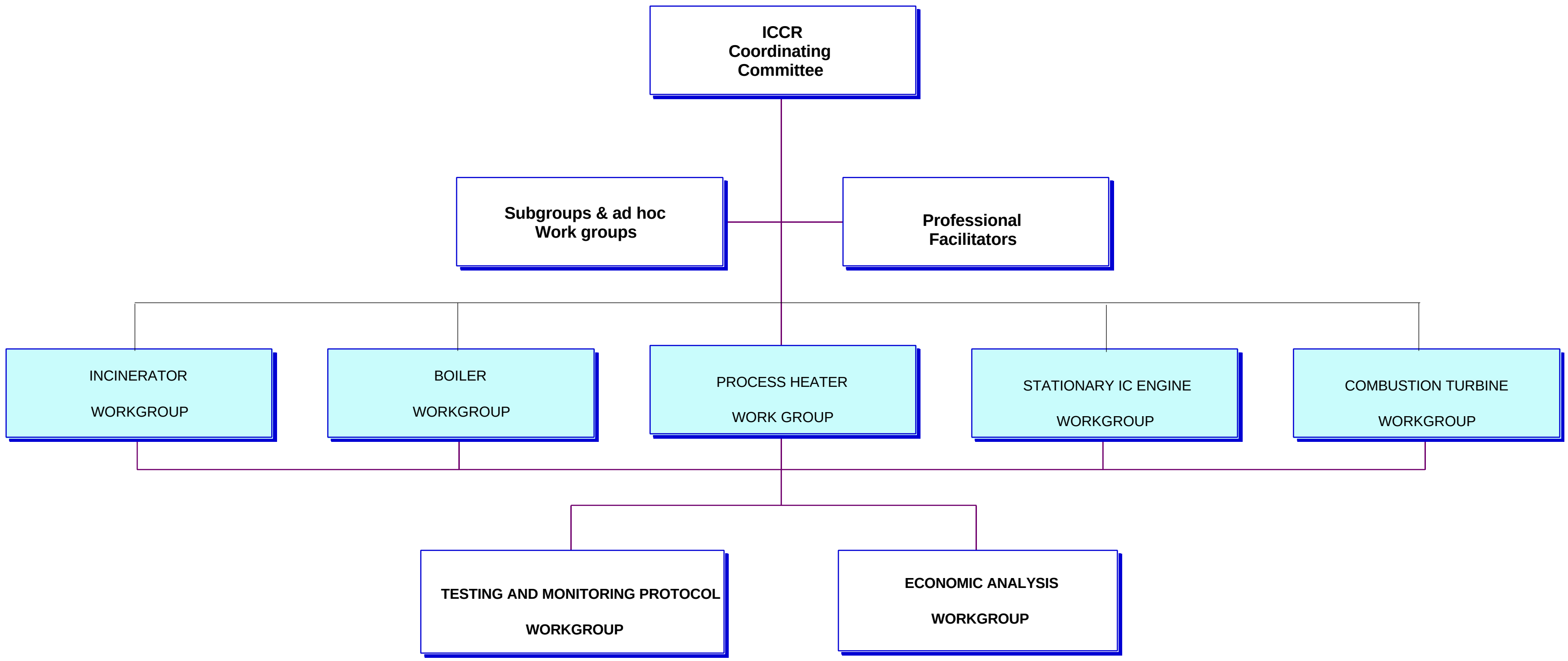


Figure 1. Illustration of ICCR Organization

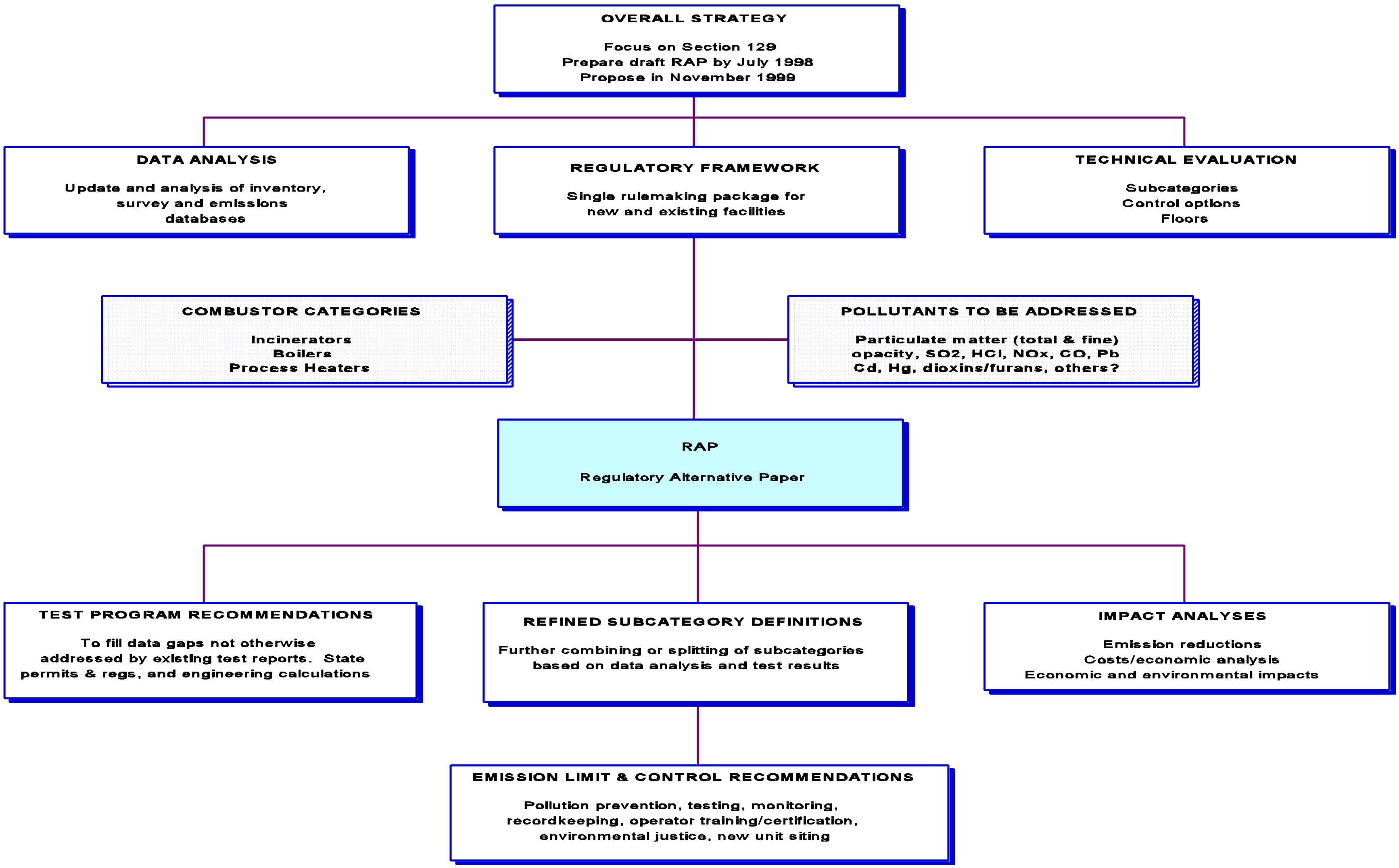


Figure 2. Illustration of IWG steps leading to the RAP and beyond.

TABLE 1. INCINERATOR WORK GROUP SUBTEAMS

SUBTEAM NO.	SUBTEAM NAME	CURRENT SUBCATEGORY RESPONSIBILITIES
1	Pathological Wastes and Crematories	▸ *Pathological wastes and crematories, including these groupings:* *a. Poultry farms ... (<100 lb/hr)* *b. Human crematories ... (100-500 lb/hr)* *c. Hospital, animal control, research facilities ... (>500 lb/hr)*
2	Chemical, Petroleum, and Pharmaceutical Solids, Liquids, and Sludges	▸ *Miscellaneous Industrial and Commercial Waste Incinerators*
3	Wood, Construction & Demolition, and Agricultural Wastes	*Wood, construction & demolition, and agricultural wastes, including these groupings:* *a. Milled solid and engineered wood* *b. Harvested wood and agricultural* *c. Construction, demolition, and treated wood*
4	Metal Parts and Drums	▸ *Drum reclaimer furnaces* ▸ *Parts reclaimer burnoff units*

TABLE 2. SUMMARY OF PRELIMINARY SUBCATEGORY DEFINITIONS

SUB-CATEGORY NAME	GROUPING WITHIN SUB-CATEGORY	MATERIAL COMBUSTED	ICWI or OSWI	EST. NO. OF UNITS		POLLUTANTS CONSIDERED FOR REGULATION	FLOOR LEVEL OF CONTROL	REGULATORY ALTERNATIVES ABOVE FLOOR
				IN DATA-BASE	NATION-WIDE			
Miscellaneous Industrial and Commercial Waste Incinerators	None identified at this time	By-products of industrial operations (including combina-tions with less that 30% municipal-type solid waste or less than 10% medical waste), environmental control device sludges, waste by-products, maintenance residues, off-test and out-dated materials, and packaging materials	ICWI	203		Section 129 pollutants	Undeter-mined: 12% of the units surveyed report controls for one or more of the following pollutants: PM, NOx, SOx, HCl, and CO	
Wood and Wood Wastes	Milled Solid and Engineered Wood Wastes	Wastes and residues resulting from wood-working manufacturing activities, containing 2 to 15 percent by weight adhesives, glues, and binders in engineered woods, and containing no more than 5 percent by weight of contam-inants such as cardboard, paper, paints, and solvents	OSWI	18		Section 129 pollutants	No control	Considering good combustion practices, source separation, particulate controls, scrubbers, ESPs, afterburners, and secondary combustors

TABLE 2. SUMMARY OF PRELIMINARY SUBCATEGORY DEFINITIONS (Continued)

SUB-CATEGORY NAME	GROUPING WITHIN SUB-CATEGORY	MATERIAL COMBUSTED	ICWI or OSWI	EST. NO. OF UNITS		POLLUTANTS CONSIDERED FOR REGULATION	FLOOR LEVEL OF CONTROL	REGULATORY ALTERNATIVES ABOVE FLOOR
				IN DATA-BASE	NATION-WIDE			
"	Harvested Wood and Agricultural Wastes	Wastes and residues resulting from land clearing, orchard, silviculture, nursery, green-house, agricultural, and forest management activities and sawmill operations and con-taining no more than 5 percent by volume of contaminants such as sand, dirt, cardboard, and paper	OSWI	8		Section 129 pollutants	No control	Considering good combustion practices, source separation, particulate controls, scrubbers, ESPs, afterburners, and secondary combustors
"	Construction, Demolition, and Treated Wood Wastes	Wastes and residues resulting from: (1) the construction, remodeling, repairing, and demolition of individual residences, commercial buildings, and other structures, and (2) the treatment of wood products that are impregnated or otherwise treated with various preservatives for the purpose of protecting or other-wise extending the structural properties of the wood	OSWI	9		Section 129 pollutants	No control	Considering good combustion practices, source separation, particulate controls, scrubbers, ESPs, afterburners, and secondary combustors

TABLE 2. SUMMARY OF PRELIMINARY SUBCATEGORY DEFINITIONS (Continued)

SUB-CATEGORY NAME	GROUPING WITHIN SUB-CATEGORY	MATERIAL COMBUSTED	ICWI or OSWI	EST. NO. OF UNITS		POLLUTANTS CONSIDERED FOR REGULATION	FLOOR LEVEL OF CONTROL	REGULATORY ALTERNATIVES ABOVE FLOOR
				IN DATA-BASE	NATION-WIDE			
Pathological Waste Incinerators and Crematories	<100 lb/hr (primarily poultry farmers; also small animal crematories, veterinary centers, humane societies, and pharma-ceutical companies)	Human or animal remains, anatomical parts and/or tissue, the bags/containers used to collect and transport the waste material, and animal bedding (if applicable)	OSWI		Potentially several thousand	Section 129 pollutants	None	See attached "Potential Incinerator Control Options" (page 45) and "Subteam #1 Recommendations for Pollution Prevention Options" (page 48)
"	100 to 500 lb/hr (primarily human crematories; also animal crematories, veterinary clinics, humane societies, and pharma-ceutical companies)	"	OSWI		2,000	Section 129 pollutants	None	See attached "Potential Incinerator Control Options" (page 45) and "Subteam #1 Recommendations for Pollution Prevention Options" (page 48)

TABLE 2. SUMMARY OF PRELIMINARY SUBCATEGORY DEFINITIONS (Continued)

SUB-CATEGORY NAME	GROUPING WITHIN SUB-CATEGORY	MATERIAL COMBUSTED	ICWI or OSWI	EST. NO. OF UNITS		POLLUTANTS CONSIDERED FOR REGULATION	FLOOR LEVEL OF CONTROL	REGULATORY ALTERNATIVES ABOVE FLOOR
				IN DATA-BASE	NATION-WIDE			
"	>500 lb/hr (primarily animal disposal systems for hospitals, animal control facilities, and research facilities)	"	OSWI		100	Section 129 pollutants	None	See attached "Potential Incinerator Control Options" (page 45) and "Subteam #1 Recommendations for Pollution Prevention Options" (page 48)
Drum Reclaimer Furnaces	None	An incinerator used to reclaim steel containers (e.g., 55 gallon drums) for re-use or to prepare them for recycling by burning or pyrolyzing interior and exterior container coatings and residues prior to cleaning by abrasive shot blasting (containers must be empty as defined by RCRA prior to processing)	ICWI	44	55	To include Section 129 list	Thermal oxidation for existing and new units	Spray dryer or wet scrubber for acid gases; fabric filter for metals; GCPs

TABLE 2. SUMMARY OF PRELIMINARY SUBCATEGORY DEFINITIONS (Continued)

SUB-CATEGORY NAME	GROUPING WITHIN SUB-CATEGORY	MATERIAL COMBUSTED	ICWI or OSWI	EST. NO. OF UNITS		POLLUTANTS CONSIDERED FOR REGULATION	FLOOR LEVEL OF CONTROL	REGULATORY ALTERNATIVES ABOVE FLOOR
				IN DATA-BASE	NATION-WIDE			
<u>Parts Reclaimer Burnoff Units</u>	None	An incinerator used to reclaim metal parts such as paint hooks and racks, electric motor armatures, transformer winding cores, and electroplating racks for use in their current form by burning off cured paint, plastisol (i.e., polyvinyl chloride and phthalate plasticizer), varnish, or unwanted parts such as plastic spacers or rubber grommets	ICWI	332	~1350	Section 129 pollutants	Thermal oxidizers for existing and new units	Spray dryer or wet scrubber for acid gases; fabric filter for metals; GCPs
<u>Potential Section 129 Solid Mixed Feed Boilers</u>	None	Various non-fossil Section 129 solid materials generally co-fired with other non-fossil materials or fossil fuels	TBD	322		Section 129 pollutants	<u>Preliminary</u>: fabric filters for metals, scrubbers for inorganic HAPs, and GCPs for organic HAPs; scrubbers for Hg from new units	<u>Preliminary</u>: carbon adsorption for organic HAPs and Hg; none identified for metals and inorganic HAPs

TABLE 2. SUMMARY OF PRELIMINARY SUBCATEGORY DEFINITIONS (Continued)

SUB-CATEGORY NAME	GROUPING WITHIN SUB-CATEGORY	MATERIAL COMBUSTED	ICWI or OSWI	EST. NO. OF UNITS		POLLUTANTS CONSIDERED FOR REGULATION	FLOOR LEVEL OF CONTROL	REGULATORY ALTERNATIVES ABOVE FLOOR
				IN DATA-BASE	NATION-WIDE			
Potential Section 129 Liquid Mixed Feed Boilers	None	Various non-fossil Section 129 liquid materials generally co-fired with other non-fossil materials or fossil fuels	TBD	153		Section 129 pollutants	Preliminary: Existing units -- ESPs for metals, scrubbers for inorganic HAPs, and GCPs for organic HAPs. New units -- fabric filters for metals, gas absorbers for inorganic HAPs, GCPs for organic HAPs, and scrubbers for Hg	Preliminary: Fabric filters for metals and carbon adsorption for organic HAPs and Hg; none identified for inorganic HAPs

ATTACHMENT A

EXAMPLE APPLICABILITY LANGUAGE AND DEFINITIONS

Subpart [?] -- Standards of Performance for Solid Waste Incineration Units for Which Construction is Commenced After [date]

Section [?] Am I subject to this regulation?

(a) Except as provided in paragraph (b) of this Section, the affected facility to which this subpart applies is each individual Solid Waste Incineration Unit for which construction or reconstruction is commenced after [date] or for which modification is commenced after [date].

(b) The following facilities are not subject to this subpart:

(1) Any incinerator or other unit required to have a permit under Section 3005 of the Solid Waste Disposal Act (subpart EEE).

(2) Any materials recovery facility (including primary or secondary smelters) which combusts waste for the primary purpose of recovering metals.

(3) Any qualifying small power production facility, as defined in Section 3(17)(C) of the Federal Power Act (16 U.S.C. 769(17)(C)), or qualifying cogeneration facilities, as defined in Section 3(18)(B) of the Federal Power Act (16 U.S.C. 796(18)(B)), which burn homogeneous waste (such as units which burn tires or used oil, but not including refuse-derived fuel) for the production of electric energy or, in the case of qualifying cogeneration facilities, which burn homogeneous waste for the production of electric energy and steam or forms of useful energy (such as heat) which are used for industrial, commercial, heating, or cooling purposes.

(4) Any air curtain incinerator that burns only wood wastes, yard wastes, and clean lumber and that complies with the opacity limitations in subpart [?].

(5) Any incinerator or other unit which meets the applicability requirements under subpart Cb, Ce, Ea, Eb, or Ec of this part (i.e., standards or guidelines for municipal waste and hospital and medical infectious waste incinerators).

(6) Municipal sewage sludge incinerators which meet the applicability requirements under subpart [?].

Sec. [?] How are the terms used in this subpart defined?

Air Curtain Incinerator means an Incinerator that operates by forcefully projecting a curtain of air across an open chamber or pit in which burning occurs; Incinerators of this type can be constructed above or below ground and with or without refractory walls and floor.

Boiler means an enclosed device using controlled flame combustion and having the primary purpose of recovering and exporting useful thermal energy in the form of hot water, saturated steam, or superheated steam. The principal components of a boiler are a burner, a firebox, a heat exchanger, and a means of creating and directing gas flow through the unit. A boiler's combustion chamber and primary energy recovery section(s) must be of integral design (i.e., the combustion chamber and the primary energy recovery section(s), such as waterwalls and superheaters, must be physically formed into one manufactured or assembled unit.) (A unit in which the combustion chamber and the primary energy recovery section(s) are joined only by ducts or connections carrying flue gas is not integrally designed; however, secondary energy recovery equipment (such as economizers or air preheaters) need not be physically formed into the same unit as the combustion chamber and the primary energy recovery section.) Only stand alone boilers are covered by this definition; waste heat boilers which are associated with stationary gas turbines or engines are excluded.

Commercial and Industrial Solid Waste Incineration Units means the following types of Solid Waste Incineration Units: Miscellaneous Industrial and Commercial Waste Incinerators; Drum Reclaimer Furnaces; Parts Reclaimer Burnoff Units; and potentially other applicable subcategories of boilers and process heaters].

Construction, Demolition, and Treated Wood Waste Incinerator means an Incinerator combusting Solid Waste comprised, in aggregate, of more than [number] percent by weight, as measured on a [time period] basis, of wastes and residues resulting from: (1) the construction, remodeling, repairing, and demolition of individual residences, commercial buildings, and other structures, including pallets; forming and framing lumber; treated lumber; shingles; tar-based products; plastics; plaster; wallboard; insulation material; broken glass; painted or contaminated lumber; chemically treated lumber; white goods; reinforcing steel; and plumbing, heating, and electrical parts; and (2) the treatment of wood products that are impregnated or otherwise treated with various preservatives (e.g., creosote, copper compounds, arsenic compounds, pentachlorophenol, [to be added]) for the purpose of protecting or otherwise extending the structural properties of the wood.

Drum Reclaimer Furnace means an incinerator used to reclaim steel containers (e.g., 55 gallon drums) for reuse or to prepare them for recycling by burning or pyrolyzing interior and exterior container coatings and residues prior to cleaning by abrasive shot blasting. (Containers must be empty as defined by RCRA prior to processing.)

Harvested Wood and Agricultural Waste Incinerator means an Incinerator combusting Solid Waste comprised, in aggregate, of more than [number] percent by weight, as measured on a [time period] basis, of wastes and residues resulting from land clearing, orchard, silviculture, nursery, greenhouse, agricultural, and forest management activities and sawmill operations and containing no more than 5 percent by volume of contaminants such as sand, dirt, cardboard, and paper.

Incinerator means any enclosed device using controlled flame combustion to combust Solid Waste for the primary purpose of reducing the volume of waste and does not incorporate heat recovery as part of its integral design.

Liquid Mixed Feed Boiler means a Boiler combusting Solid Waste comprised, in aggregate, of more than [number] percent by weight, as measured on a [time period] basis, of various non-fossil liquid materials which are generally co-fired with other non-fossil materials or fossil fuels.

Milled Solid and Engineered Wood Waste Incinerator means an Incinerator combusting Solid Waste comprised, in aggregate, of more than [number] percent by weight, as measured on a [time period] basis, of wastes and residues resulting from woodworking manufacturing activities, containing 2 to 15 percent by weight adhesives, glues, and binders in engineered woods, and containing no more than 5 percent by weight of contaminants such as cardboard, paper, paints, and solvents.

Miscellaneous Industrial and Commercial Waste Incinerator means an Incinerator combusting Solid Waste comprised, in aggregate, of more than [number] percent by weight, as measured on an annual basis, of byproducts of industrial operations (including combinations with less that 30% trash or less than 10% medical waste), environmental control device sludges, waste byproducts, maintenance residues, off-test and out-dated materials, and packaging materials.

Other Solid Waste Incineration Unit means the following types of Solid Waste Incineration Units: Construction, Demolition, and Treated Wood Waste Incinerators; Harvested Wood and Agricultural Waste Incinerators; Milled Solid and Engineered Wood Waste Incinerators; Pathological Waste Incinerators and Crematories; and potentially other applicable subcategories of boilers and process heaters].

Parts Reclaimer Burnoff Unit means an Incinerator used to reclaim metal parts such as paint hooks and racks, electric motor armatures, transformer winding cores, and electroplating racks for use in their current form by burning off cured paint, plastisol (i.e., polyvinyl chloride and phthalate plasticizer), varnish, or unwanted parts such as plastic spacers or rubber grommets.

Pathological Waste Incinerator and Crematory Unit means an Incinerator combusting Solid Waste comprised, in aggregate, of more than 90 percent by weight, as measured on a daily basis (and more than 70 percent on an individual batch basis), of only human or animal remains, anatomical parts and/or tissue, the bags/containers used to collect and transport the waste material, and animal bedding (if applicable).

Process Heater means an enclosed device using a controlled flame with physical provisions for recovery and exporting thermal energy to an industrial or commercial process or process stream, principally in a form other than hot water, saturated steam, or superheated steam.

Solid Mixed Feed Boiler means a Boiler combusting Solid Waste comprised, in aggregate, of more than [number] percent by weight, as measured on a [time period] basis, of various non-fossil solid materials which are generally co-fired with other non-fossil materials or fossil fuels.

Solid Waste means ... [This definition is currently under discussion at EPA. The definition will apply only to units under Section 129 that combust nonhazardous solid waste.]

Solid Waste Incineration Unit means a distinct operating unit of any facility which combusts any Solid Waste material from commercial or industrial establishments or the general public (including single and multiple residences, hotels, and motels), including Commercial and Industrial Solid Waste Incineration Units and Other Solid Waste Incineration Units, but excluding the facilities identified in section [?](b).

ATTACHMENT B

DRAFT SUBCATEGORY DEFINITION SHEETS

SUBCATEGORY NAME: Miscellaneous Industrial and Commercial Waste Incinerators

ASSIGNED CAA Section (ICWI OR OSWI): Section 129 (ICWI)

GROUPINGS WITHIN SUBCATEGORY:

This subcategory includes incinerators operated by industry in the twenty three (23) SIC groupings including the following: 13, 20, 22, 23, 24, 26, 28, 29, 30, 33, 34, 35,36, 37, 42, 46, 49, 51, 55, 73, 75, 87, 92, 97. These include the following industries:

Aircraft
Catalyst manufacturing
Government/municipality
Industrial organic and inorganic chemicals
Metal products
Oil and gas
Petrochemical
Photo processing
Pharmaceutical
Tire and rubber

Incinerators in this subcategory are located in 29 states as follows:

Arkansas (4), Alabama (2), California (21), Connecticut (9), Georgia (2), Iowa (6), Idaho (1), Illinois (3), Indiana (11), Kansas (1), Louisiana (13), Massachusetts (6), Maine (3), Michigan (13), North Carolina (9), North Dakota (2), Nebraska (2), New Jersey (7), Ohio (5), Pennsylvania (15), Puerto Rico (12), South Carolina (8), Tennessee (8), Texas (36), Virginia (9), Washington (6), Wisconsin (5), West Virginia (2).

The workgroup found no basis for subcategorization based on industry type or waste type. The workgroup has not yet evaluated the potential for subcategorization based on size, feed rate, or incinerator type (continuous or batch).

POPULATION STATISTICS:

Nationwide, there are 203 units assigned to this subcategory based on the EPA databases. The number of units in this subcategory will increase as units in the uncharacterized incinerator database are assigned to subcategories. This could cause the database to double but would not necessarily add new characterization data. It should also be noted that the number of units in this subcategory has decreased since the ICCR Incinerator workgroup began working with the population database. The workgroup speculates that owners and operators are turning to commercial waste destruction facilities or alternate waste disposal methods including pollution prevention techniques. As a result, while new plants may be constructed in the future, the general trend will be toward a reduction in the population of this type on incinerator.

The workgroup has not characterized the database information based on the size of a particular unit or its throughput capacity. Either of these characterizations could form the basis for further subcategorization of this subcategory. These data may be contained in the survey database or in the test report information.

This subcategory is also characterized by units that are operated as either batch or continuous units. The type of operation can form the basis for further subcategorization   The workgroup has not completed an analysis of the impact of the type of operation (i.e. batch vs. continuous) on the subcategorization.

MATERIAL COMBUSTED:

Byproducts of industrial operations, including combinations with less that 30% trash or less than 10% medical waste, environmental control device sludges, industrial process biosolids, waste byproducts, maintenance residues, off-test and out-dated materials, and packaging materials.

Based on inventory data, waste descriptions include:

> Aqueous waste, commercial and industrial wastes, decorative laminate/cast polymer scrap, industrial sludge, industrial wastewater sludge, liquid wastes, medical waste (less than 10 percent of total feed), municipal solid waste (below 30 percent of Feed), plastics, waste oil, pathological wastes, finishing wastes and paint wastes.

Attached is a list, extracted from the subcategory database, of the wastes that are destroyed in the subcategory's units. As can be seen from the list, no particular waste predominates. This subcategory cannot support groupings based on the material burned.

COMBUSTION DEVICE: All types of incinerators are used in this subcategory, including, but not limited to, single and multiple chamber (including multiple hearth), fluid bed, rotary kilns, and tray types. The breakdown of units is as follows:

Multiple Chamber	45.2%
Single Chamber	25.4%
Rotary	9.7 %
Fluidized Bed	2.3 %
Otherwise classified	1.4%
Unclassified	16.0%

A more detailed list of combustion devices is attached.

Air pollution control devices are generally add-on units whose use is driven by state regulations and permit conditions. The database contains information on controls device on 78 of 203 units. Of these 78 units, 20 had no controls. Of the remaining 58 units, the database indicates that they were equipped with 124 control devices. 45 units have control devices for particulates (58%), 25 units have controls for CO (32%), 17 units have SOx control devices (22%), 20 units have devices for controlling NOx (26%) and 20 of which have control devices for HCl (26%). Many of the 58 units with controls have redundant controls, apparently due to state requirements presumably aimed at ensuring high reliability. Units with multiple control devices which may actually be multiple units are not accurately depicted in the data base but may be easier to identify from original survey sheets. (Note: The representativeness of the above 78 units relative to the total number of units in the database (203) in terms of control device use must be determined.)

PM control equipment listed in the database include wet scrubbers, wet cyclone separators, venturi scrubbers, single cyclones, packed columns, multiple cyclones, mist eliminators, impingement plate scrubbers, ESP, afterburners, chemical neutralization, fabric filters.

CO control equipment listed in the database include air/fuel ratio control, afterburner, and staged combustion.

SOx control equipment listed in the database include venturi scrubbers, sodium alkali scrubbing systems, packed absorption, mist eliminators, impingement plate scrubbers, sorbent injection, chemical neutralization, and alkalized fly ash scrubbers.

NOx control equipment listed in the database include air to fuel ratio control, ammonia injection, chemical neutralization, impingement plate scrubber, low NOx burners, low excess air firing, packed absorption column, staged combustion, and venturi scrubbers.

HCl control equipment listed in the database include wet scrubbers, venturi scrubber, packed column, mist eliminator, sorbent injection, chemical neutralization, and flyash alkaline scrubbing.

A further breakout of the air pollution control devices is attached.

BASIS FOR SUBCATEGORY BOUNDS: This subcategory includes solids, liquid, and sludge incinerators mostly within SIC code 28, but includes incinerators burning a range or variety of materials at all types of facilities. Of the total number of units in the database, 53.9% were from the 28 SIC grouping. Based on the current analysis of the database, there is insufficient information to determine whether there are statistically significant groupings of emissions over the category, although further analysis might indicate some basis for subcategorization based on the size of the incinerator, the throughput of the incinerator, or the type of operation (batch vs continuous).

POLLUTANTS CONSIDERED FOR REGULATION: Particulate matter (total and fine), opacity (as appropriate), SO_2, HCl, NOx, CO, Pb, Cd, Hg, and dioxins and furans.

FLOOR LEVEL OF CONTROL: The workgroup has not reviewed performance test data for the individual units to determine the MACT floor. Although more than 12 percent of the units have some types of controls, there is also a large percentage with no control.   Significant number of units (i.e. more than 12 percent) reported some type of control for particulates, SO_2, HCl, NOx, or CO. The analysis of the data is incomplete, and it was not determined how many units control multiple pollutants. Control for one or more of these pollutants could be considered as the MACT floor. However, the actual limit associated with this control technique has not been established. No control devices have been identified for Pb, Cd, Hg, or dioxins and furans, although it may be assumed that particulate controls will reduce Pb and Cd.

REGULATORY ALTERNATIVES ABOVE FLOOR: The subteam has not examined the above the floor alternatives and new equipment alternatives. However, the group suggests that the Hazardous Waste MACT and Medical Waste MACT be reviewed to form a plan for completing this task. Based on the high level of control and regulation of this subcategory, the group believes it is unlikely that there is justification to regulate beyond the floor for particulates, SO_2, HCl, NOx or CO. However, there might be justification for additional controls for Hg, Pb, Cd, or dioxins, if they are present.

STATUS OF DATA COLLECTION AND ANALYSIS: The subteam has contacted many of the sources who responded to the ICR survey to obtain information about applicable permit conditions and State standards. Information of this nature has been obtained and tabulated for approximately 15 units with the potential for more information being received in the near future. The subteam has also made a list of those facilities for which emissions test data are available. The subteam has created spreadsheets which provide detail regarding the air pollution control devices on each surveyed source and what Section 129 pollutant(s) each may control. That spreadsheet has been arranged according to how effectively each device can control a given pollutant in order to provide some insight into what type of control may be appropriate for selection as MACT floor for existing and new units.

ISSUES AND NEEDS: A review of the State regulations for combustion emissions needs to be completed. There is also a need to confirm that size, throughput, or type of operation does not impact emissions or the cost of control and therefore subcategorization.

LIST OF MISCELLANEOUS INDUSTRIAL AND COMMERCIAL WASTE DESCRIPTIONS, NUMBER OF UNITS, AND PERCENTAGE OF UNITS IN DATABASE

1,4 butanediol heavy ends, 1, 0.42%
5% office paper, 95% paint sweepings and paint booth, 1, 0.42%
50-500 ppm PCB's/other (unidentified), ,1 0.42%
98% water, 2% anti-static liquid mixed with water, 1, 0.42%
Activated sludge from a pharmaceutical manufacturing plant wastewater treatment, 1, 0.42%
Aniline/other (unidentified), 1, 0.42%
Biological secondary sludge from aerobic treatment of industrial wastewater, 1, 0.42%
By-product waste, 1, 0.42%
Carbon black, 2, 0.84%
Coal tar waste/mixed industrial, 1, 0.42%
Confidential papers, 1, 0.42%
Contaminated trash from ammunition production lines, 1, 0.42%
Coproduct of partial acidation process, 1, 0.42%
Decorative laminate/cast polymer scrap, 1, 0.42%
Diesel fuel, 2, 0.84%
Disposal of pyrophoric samples, 1, 0.42%
Distillate from reactors containing approximately 7 NT % TOC, 1, 0.42%
Distillate or water by-product generated by condensation, 1, 0.42%
Ethyl acetate isopropanol, 1, 0.42%

Fabric scraps and lint, 1, 0.42%
Fiber paint booth filters & paper waste ,1, 0.42%
Fiberglass overspray filters loaded with overspray from finish system ,1, 0.42%
Fibers waste, 2, 0.84%
Fumes from reactors, 1, 0.42%
Gauzes, dispensary wastes, oily rags, floor sweepings, plastics, paper, and cardboard, 1, 0.42%
Illegal drugs and combustible contraband, 1, 0.42%
Industrial sludge, 1, 0.42%
Industrial solid waste (non-hazardous) ,1, 0.42%
Industrial waste materials, 1, 0.42%
Industrial waste/waste oil ,1, 0.42%
Industrial wastewater sludge, 6, 2.52%
Industrial wastewater sludge from bulk pharma-chemical manufacturing, 1, 0.42%
Lacquer dust from spray booth clean up as well as scrapings and filters, 1, 0.42%
Lead-free, chrome- free paint sludge (~10% solvent, ~90% solids), 1, 0.42%
Liquid hydrocarbon wastes containing salts and catalyst, 1, 0.42%
Liquid waste from air oxidation process, 1, 0.42%
LPG, 10 ,4.20%
Medical waste, 1, 0.42%
Microfiche (15%), paper (5%), and Mylar/mixed, 1, 0.42%
Mineral spirits fumes burned off without condensation, 2, 0.84%
Mixture containing 2/3 common trash, 1/3 non-hazardous chemicals (plastics, foam etc.), 1, 0.42%
Mixture of combustible waste such as non-recycled paper, cardboard carton, floor sweepings, 1, 0.42%
Molded paper articles containing nitrocellulose, 1, 0.42%
Molded paper articles containing nitrocellulose, 1, 0.42%
Multiple effect evaporator concentrate; concentrated blowdown from cooling tower, 1, 0.42%
Municipal/commercial solid waste: type 0 - trash, 3, 1.26%
N-methyl pyrrolidine residue, 1, 0.42%
Natural gas, 43, 18.07%
NCGS from pulping operations, 1, 0.42%
Nitric acid fumes as No 3 and NO 2, 2, 0.84%
No. 2 distillate, 15, 6.30%
No. 6 residual oil, 1, 0.42%
Non-hazardous industrial solid waste, including off-spec pharmaceutical and other, 1, 0.42%
Non-hazardous liquid distillates generated from pioneer's, 1, 0.42%
Non-hazardous, non-RCRA, non-DOT regulated polyols, 1, 0.42%
Off spec pharmaceutical products & packaging components, 1, 0.42%
Off-gas from air oxidation process, storage tank vents, distillation vents, 1, 0.42%
Off-specification diaper raw materials and trim waste, paper, corrugated cartons, plastic, 1, 0.42%
Oil filters & process filters oil & gas, 1, 0.42%
Oil filters, oil field trash, process filters ,1, 0.42%
Oil soaked pads - oil absorbent bags from floor drains, 1, 0.42%
Oily absorbents used for soaking up spilled motor and hydraulic oils, 1, 0.42%
Organic fumes from condensation reaction of unsaturated polyester resin, 1, 0.42%
Oxidized waxes and petroleum, 1, 0.42%
Paint booth filters & paint dust, 1, 0.42%
Paint both filters containing cured 2-part urethane paint; floor sweepings, 1 ,0.42%
Paint filters and varnish dust, 1, 0.42%
Pallets, 2, 0.84%
Paper mill sludge from waste treatment plant-deink tissue mill, 1, 0.42%
Paper slurry containing nitrocellulose, 2 ,0.84%
Pathological: animal remains, 1, 0.42%
Petrochemical process gas, 1, 0.42%
Phosphate cleaner & paint waste, 1, 0.42%
Phosphate cleaner waste, 1, 0.42%

Plastics ,5, 2.10%
Polypropylene carpet backing, 1, 0.42%
Process off-gas from herbicide production, 1, 0.42%
Process wax composed of fillers and resins, 1, 0.42%
Pulp mill non-condensible gases , 1, 0.42%
PVC/styrene/abs/hdpe/ldpe/ (plastics), 1, 0.42%
Quantity of wax, 1, 0.42%
Rectified methanol from pulpmill condensates, 1, 0.42%
Refined petroleum contaminated debris, 1, 0.42%
Regulated medical waste such as discarded wipes, gauze, gowns, gloves, bandages, 1, 0.42%
Residue from herbicide intermediate production, 1, 0.42%
Returned pharmaceutical products with packaging (non-hazardous), 1, 0.42%
Single chamber incinerator, 1, 0.42%
Solids from manufacturing and product storage, 1, 0.42%
Solids/other (unidentified), 1, 0.42%
Stoddard calibration fluid, 1, 0.42%
Sulfur-free organic by-product/other (unidentified), 1, 0.42%
Tablets, capsules, non-corrugated carton, 1, 0.42%
Tar oil; similar to no 6 fuel oil, 16,000 btu/lb, 1, 0.42%
Turpentine and methanol from foul condensate stripper, 1, 0.42%
Undefined solid waste (explosives), 1, 0.42%
Undefined solid waste (fertilizer)/other (unidentified), 1, 0.42%
Undefined solid waste (laboratory waste)/other (unidentified), 1, 0.42%
Undefined solid waste (metal coating)/finishing waste, 3, 1.26%
Undefined solid waste (photofinishing)/photo processing, 1, 0.42%
Undefined solid waste (toilet preparations; cosmetics, 1, 0.42%
Undefined waste (plastics, synthetic materials, etc), 1, 0.42%
Unknown/finishing wastes, 1, 0.42%
Used air filters from paint booths, dirty rags, drip paper from paint booths, 1, 0.42%
Vapor from stoddard calibration fluid, 1, 0.42%
Vegetable oil, coconut oil, rice oil, silicone oil, 1, 0.42%
Vent gases produced in manufacturing and product storage, 1, 0.42%
Vinyls/other (unidentified), 1, 0.42%
Volatile organic compounds from pioneer's, 1, 0.42%
Waste activated charcoal and waste diatomaceous earth used as filter media, 1, 0.42%
Waste carbon black, 1, 0.42%
Waste ethical drugs, sweeping, etc., waste narcotic controlled drugs, 1, 0.42%
Waste excess activated sludge from permitted wastewater treatment plant, 1, 0.42%
Waste fluids, 3, 1.26%
Waste fluids/other (unidentified), 2, 0.84%
Waste from fibers processing, primarily fishing, 2, 0.84%
Waste lint/other (unidentified), 1, 0.42%
Waste lubrication oils, 1, 0.42%
Waste oil, 7, 2.94%
Waste type 1, 1, 0.42%
Waste water sludge from auto painting, 1, 0.42%
Water used to wet rags for wiping off furniture parts is evaporated in the incinerator, ,1 0.42%
Water vapor with varying amounts of organics, 1, 0.42%
Water with varying amounts of organics, 1, 0.42%
Wax composed of fillers and resins, 1, 0.42%
Wood: dried milled lumber, 1, 0.42%
Unspecified, 18, 7.56%
Total in database, 238

LIST OF MISCELLANEOUS INDUSTRIAL AND COMMERCIAL WASTE COMBUSTION DEVICES AND NUMBER OF DEVICES IN DATABASE

Catalytic, 2
Extrusion incinerator, 1
Excess air, fluid bed, single batch fed, 2
Fluidized-bed, 1
Suspension firing, fluid bed, continuously fed, 2
Burn-off oven, multi-chamber, excess air, intermittent batch fed, 2
Burn-off oven, multi-chamber, starved air, single batch fed, 1
Fixed hearth, multi-chamber, excess air, intermittent batch fed, 10
Fixed hearth, multi-chamber, excess air, single batch fed, 3
Fixed hearth, multi-chamber, intermittent batch fed, 4
Fixed hearth, multi-chamber, single batch fed, 2
Fixed hearth, multi-chamber, starved air, intermittent batch fed, 3
Multi-chamber, continuously fed, 2
Multi-chamber, continuously fed, down fired, 3
Multi-chamber, continuously fed, sudden expansion, 3
Multi-chamber, excess air, automatic feeder, 8
Multi-chamber, excess air, continuously fed, 3
Multi-chamber, excess air, intermittent batch fed, 4
Multi-chamber, excess air, starved air, 4
Multi-chamber, intermittent batch fed, 3
Multi-chamber, intermittent batch fed, continuously fed, 3
Multi-chamber, single batch fed, 12
Multi-chamber, starved air, single batch fed, 4
Multiple chamber (could be starved or excess air), 5
Multiple hearth, 1
Multiple hearth, continuously fed, 4
Multiple hearth, excess air, continuously fed, 2
Pathological, fixed hearth, multi-chamber, excess air, starved air, intermittent batch fed, medical, 2
Pathological, multi-chamber, intermittent batch fed, medical waste, rocking kiln, 6
Spreader stoker, multi-chamber, excess air, single batch fed, 2
Suspension firing, multi-chamber, intermittent batch fed, 2
Rotary hearth, 3
Rotary kiln, 4
Rotary kiln, multi-chamber, continuously fed, 2
Rotary kiln, multi-chamber, excess air, intermittent batch fed, 5
Fire tube, induced draft, rotary kiln, multi-chamber, excess air, continuously fed, 3
Metals recovery, rotary hearth, 4
Single chamber, 13
Single chamber, continuously fed, 12
Single chamber, down-fired thermal oxidizer liquid incinerator, 3
Single chamber, excess air, continuously fed, 11
Single chamber, excess air, fluid bed, continuously fed, 3
Single chamber, excess air, single batch fed, 1
Single chamber, single batch fed, 3
Burn-off oven, single chamber, excess air, intermittent batch fed, 2
Fixed hearth, single chamber, excess air, 2
Single chamber, single batch fed, with after burner, 2
Suspension firing, single chamber, excess air, continuously fed, 3
Burn-off oven, 2
Continuously fed, 5
Excess air, continuously fed, 4
Furnace, 1

Incinerator, 3
Incinerator, metals recovery, pathological, single batch fed, 4
Oxidation plant, 1
Pathological, fixed hearth, starved air, single batch fed, 3
Suspension firing, excess air, continuously fed, 2
Unspecified incinerator, 6
Unspecified incinerator/UR 1500, 2
Used oil heater, 1
Total in database, 316

LIST OF MISCELLANEOUS INDUSTRIAL AND COMMERCIAL WASTE INCINERATION EMISSION CONTROL DEVICES AND NUMBER OF DEVICES IN DATABASE

Direct flame afterburner, 20
Direct flame afterburner - heat exchange, 2
Electrostatic precipitator, high efficiency, 3
Fabric filter, high temperature, 3
Fabric filter, medium temperature, 6
Impingement plate scrubber, 1
Mist eliminator, high velocity, 4
Mist eliminator, low velocity, 1
Multiple cyclone w/o fly, 2
Packed-gas absorption column, 4
Single cyclone devices, 5
Venturi scrubber, 15
Wet cyclonic separator, 5
Wet scrubber, high efficiency, 6
Wet scrubber, medium efficiency, 3

SUBCATEGORY NAME: Wood and Wood Waste Incinerators

ASSIGNED CAA SECTION (ICWI OR OSWI): Section 129 (OSWI).

GROUPINGS WITHIN SUBCATEGORY:

Milled Solid and Engineered Wood Wastes
Harvested Wood and Agricultural Wastes
Construction, Demolition, and Treated Wood Wastes

POPULATION STATISTICS:

All units identified in the database as combusting materials associated with agricultural activities were individually verified. Of the 18 units listed in the database, no units were found to be incinerators actually combusting agricultural types of materials. Seven units were no longer in existence, five units were small MWC's, four units were combusting materials within the purview of other workgroups and were therefore transferred, one unit was a boiler, and one unit was a process heater. Two agricultural trade associations and a multinational company were solicited by the subteam for assistance in identifying agricultural incineration units within their organizational membership and outside the database. Neither were able to verify the existence of such units. Thus, it is the belief of the subteam that incineration units dedicated to the combustion of agricultural waste are few to non-existent. If such units exist, it is the belief of the subteam that these units are small to very small in nature.

Twenty two units were identified within the database as combusting various types of wood materials. The subteam independently verified each of these units -- nine units were identified as being "air curtain" incineration units, seven units were identified as small to very small incineration units without specific pollution controls combusting various types of wood materials, two units were MWC's, one unit was a teepee, one unit was an open burning operation, one unit was a boiler, and one unit is no longer in operation.

The identified incineration units are believed to reasonably represent the domestic population of wood incinerators and to include the bulk of existing units. The geographic coverage of the database includes all States where such units would be expected to be concentrated. The wood incinerators data should be at least as representative as EPA's ICCR databases as a whole. Due to the incentive to burn wood materials for heat recovery (e.g., in boilers), the population of wood incinerators is believed to be static or in decline.

The subteam believes that air curtain units are properly addressed under Section 129 g(1) of the rule in which air curtain units are exempted from this rulemaking if they burn wood waste, yard waste, and clean lumber and comply with opacity limits as set forth by the Administrator. It is also the understanding of the subteam that under the current MWC rules, there are no opacity limits specified for air curtain units burning the above materials.

The subteam believes there may be more teepee and open burning operations combusting wood than has been identified in the database. The subteam believes that various State permit conditions dealing with these units provide valuable guidance and should be consulted and reviewed prior to the setting of any federal conditions or standards. The subteam recommends consideration of basing any federal recommendations for teepees and open burning on the State rules.

Of the seven units identified by the subteam as incineration units combusting various materials consisting of wood, the subteam has found these units to be small to very small in size. These units were also found to have no specific pollution control and were operating infrequently on an as needed or batch basis. Therefore, the subteam has determined that these units are difficult to control outside of good combustion practices. Although the number of units identified in the database combusting these materials is small, the subteam has concluded that the database is correct in that most wood type materials are combusted as fuels in boilers.

MATERIALS COMBUSTED:

Milled Solid and Engineered Wood Wastes. Wastes and residues resulting from woodworking manufacturing activities. The specific characteristics of these materials vary depending on the specie of wood (e.g., pine, oak, and poplar) and the engineered wood (e.g. particleboard, plywood, and fiberboard) used. The proportion of adhesives, glues, and binders normally found in engineered wood ranges from 2 to 15 percent by weight depending on the product. The composition is variable and contains no more than 5 percent by weight of other contaminants such as cardboard, paper, paints, and solvents.

Harvested Wood and Agricultural Wastes. Wastes and residues resulting from land clearing, orchard, silviculture, nursery, greenhouse, agricultural, and forest management activities and sawmill operations. The combustion characteristics of these materials vary, and the moisture content typically ranges from 20 to 60%. Some wastes may contain residual chemical compounds from pesticide and herbicide treatment of vegetation. The composition contains no more than 5 percent by volume of contaminants such as sand, dirt, cardboard, and paper.

Construction, Demolition, and Treated Wood Wastes. *Construction wastes* are wastes and residues resulting from the construction, remodeling, and repairing of individual residences, commercial buildings, and other structures. The composition is variable and generally includes pallets, forming and framing lumber, treated lumber, shingles, tar-based products, plastics, plaster, wallboard, insulation material, plumbing, heating, and electrical parts. *Demolition wastes* are generally the same as construction wastes but may include broken glass, painted or contaminated lumber, chemically treated lumber, white goods, and reinforcing steel. *Treated wood wastes* are wastes and residues resulting from the treatment of wood products that are impregnated or otherwise treated with various preservatives (e.g., creosote, copper compounds, arsenic compounds, pentachlorophenol, [additional preservatives to be added]) for the purpose of protecting or otherwise extending the structural properties of the wood. The composition is variable and contains such contaminants as organic and inorganic chemicals, metals, oils, paint, solvents, and pigments.

COMBUSTION DEVICE: Includes single and multi-chamber and fluidized bed incinerators (i.e., devices without heat recovery) of various sizes, and also open burning, air curtain incinerators and teepees. The types of waste combusted in each of these combustion devices is illustrated in the following matrix.

COMBUSTION DEVICE	WOOD AND WOOD WASTE TYPE		
	Milled solid and engineered	Harvested wood and agricultural	Construction, demolition, and treated
Open burning		✔	?
Air curtain	?	✔	?
Teepee	✔	?	?
Incinerator	✔	?	✔

BASIS FOR SUBCATEGORY BOUNDS: Waste and equipment type and possibly size; other criteria are being considered.

POLLUTANTS CONSIDERED FOR REGULATION: Section 129 Pollutants.

FLOOR LEVEL OF CONTROL: The floor for existing units is no control, based on the absence of any controls among those units found in the inventory and survey databases. State regulations and permits were not found for these units, except for several opacity limits. A best controlled similar unit for determining the new unit floor was not identified.

REGULATORY ALTERNATIVES ABOVE FLOOR: Yet to be evaluated, but considering good combustion practices, source separation, particulate controls, scrubbers, ESPs, afterburners, and secondary combustors.

STATUS OF DATA COLLECTION AND ANALYSIS: The survey database indicates six units to have test data, and actions have been initiated to obtain these test reports. The database indicates 11 units to have some kind of control, but independent verification by the Subteam identified no units as having controls. Two units were identified by the Subteam as being teepee burners and 2 units were identified as air curtains.

ISSUES AND NEEDS: Test data are lacking. Additional testing may be needed for milled, harvested, and treated wood wastes, although due to the small number of units in the category, the subteam does not recommend testing at this time. Instead, the subteam believes that adequate data of good quality currently exist within State permit conditions and regulations and that these data should be used to establish emission limits.

OTHER COMMENTS:

The Subteam does not know if the applicability of an agricultural subcategory is valid. Although independent verification of the 18 facilities listed as agricultural facilities in the database indicated that no such facility or unit exists, the Subteam will continue to carry this category until a more definitive determination is made. For emissions data, the Subteam is considering a NY/EPA test summary, tests reported in the 1998 EPA dioxin emissions inventory report, and test data reported in the ICR survey responses. A number of survey test reports have been requested.

It may be reasonable to combine the three wood and wood waste groupings into a single category (e.g. the miscellaneous industrial and commercial wood waste subcategory), since there are so few wood and wood waste units and there are similarities in emissions and controls. The subteam recommends that EPA first consider whether separate emission limits can be established for each wood and wood waste grouping. If this proves to be infeasible, the merging of wood and wood waste into a single miscellaneous industrial and commercial wood waste subcategory may be necessary.

A list of wood and wood waste facilities, unit types, and controls is presented below. This list was initially compiled from the inventory and survey databases. Contacts were then made with individual facilities to determine their operational status. Facilities found not to be in operation or otherwise misclassified were deleted from the initial list, resulting in the revised list presented below.

ICCR#	Facility Name	Unit Type	Type of Controls
450130037	Malphrus Construction #2	Air Curtain	None
220330013	La Skid and Pallet	Air Curtain	None
19059W350	Stylecraft, Inc	Incinerator	None
19059W350	Stylecraft, Inc	Incinerator	None
19059W350	Stylecraft, Inc	Incinerator	None
300670003	Park Lumber Company	Teepee	None
470830063	Imperial Fabricating Company	Incinerator	None
470890001	Burroughs-Ross Colville	Open Burning	None
47163A280	City of Kingsport	Air Curtain	None
47005A246	City of Alcoa	Air Curtain	None
120990233	Marks Landscaping & Paving	Air Curtain	None
530470015	Zosel Lumber	Incinerator	None
511750050	Atlantic Wood	Air Curtain	None
160490002	L.D. McFarland	Air Curtain	None
170312435	Service Products Inc	Incinerator	None
390775014	R.R. Donnelley & Sons	Incinerator	None

482010110	Cagle Constructors	Air Curtain	None
482010110	Cagle Constructors	Air Curtain	None
482010110	Cagle Constructors	Air Curtain	None
550750390	Fruday Canning Corp	Incinerator	None

SUBCATEGORY NAME: Pathological Waste Incinerators and Crematories

ASSIGNED CAA Section (ICWI OR OSWI): Section 129 (OSWI).

GROUPINGS WITHIN SUBCATEGORY:

By mass burn rates as follows: less than 100 lb/hr; 100 to 500 lb/hr; over 500 lb/hr. These groupings were made based on categories typically seen in the field, with each group tending to have a distinct design, complexity, size, and method of utilization. Differences in emission rates due to design, waste profiles, or any other factors are not known due to insufficient data. Profiles for each of these groups are given below. Grouping is also possible by the amount and composition of material burned that is not animal or human remains.

Less than 100 lb/hr mass burn rate

Typical user profile - primarily poultry farmers; secondarily small animal crematories, veterinary centers, humane societies, and pharmaceutical companies. Little or no training on operating parameters by a qualified source.

Annual operating hours per unit - unknown

Typical waste profile - primarily poultry carcasses; secondarily small animal remains, the bags/containers used to collect and transport the waste material, and animal bedding.

Typical design profile - for poultry units: single chamber systems; fueled with #2 fuel oil, LP gas, or natural gas; no air or temperature controls; manual operating system; batch fed; no add-on emission controls.

100 to 500 lb/hr mass burn rate

Typical user profile - primarily human crematories; secondarily: animal crematories; veterinary clinics; humane societies; and pharmaceutical companies. Training often required and usually conducted by manufacturers or service organizations.

Annual operating hours per unit - 700

Typical waste profile - primarily human remains and associated containers; secondarily: animal remains, the bags/containers used to collect and transport the waste material, and animal bedding.

Typical design profile - retort and in-line systems, as described below; fueled with natural gas, LP gas, or #2 fuel oil; limited air controls; limited temperature controls; manual control system; batch fed; no add-on emissions control devices.

Greater than 500 lb/hr mass burn rate

Typical user profile **-** primarily animal disposal systems for hospitals, animal control facilities, and research facilities.

Annual operating hours per unit **-** 1000

Typical waste profile **-** primarily animal remains, the bags/containers used to contain them, and animal bedding.

Typical design profile **-** multi-chamber design as described below; fueled with natural gas, LP gas, or #2 fuel oil; air and temperature controls; automatic control systems; mechanical feed with intermittent charging; no add-on emissions control devices.

POPULATION STATISTICS:

Nationwide estimate by size groupings:

Less than 100 lb/hr - possibly several thousand units, based on discussions with the manufacturers of these types of units. However, we believe many of these units are not permitted or registered and therefore are under-represented in the database.

100 to 500 lb/hr - 2000 units, based on information from the Cremation Association of North America (CANA) and leading equipment manufacturers.

Over 500 lb/hr - 100 units, based on communication with the manufacturers.

The population estimates shown are significantly higher than is indicated by the database, especially in the case of the less than 100 lb/hr units

MATERIALS COMBUSTED: Pathological waste is waste material consisting of only human or animal remains, anatomical parts and/or tissue, the bags/containers used to collect and transport the waste material, and animal bedding, if applicable *(from the HMIWI MACT)*.

COMBUSTION DEVICE:

These combustors are generally single or multiple chamber designs. They are fueled with fossil fuel and operate with excess air. The wastes, consisting of at least 90% by mass pathological waste as defined above, are fed as single batches or intermittently fed. (Subteam #1 recommends that the 90% limit be determined on a daily basis, but at no time shall any batch consist of less than 70% pathological material.) Typically these combustors have no add-on emission control devices.

A crematory incinerator is a pathological waste incinerator which is primarily used to reduce single batches of human or animal remains and their containers (pathological waste) to their basic elements with the intent of recovering the cremated remains for memorialization purposes.

Pathological waste combustors can be classified into the following design categories:

Retort incinerators - multiple chamber incinerator designs in which the secondary chamber is located directly beneath the primary chamber. The purpose of this configuration is that the hearth of the primary chamber is heated by the products of combustion flowing through the secondary chamber. This type of design is superior for controlling fluids involved in the incineration of human and animal tissue. Because the temperature of the secondary chamber affects the temperature of the primary chamber, excessive temperature in the secondary chamber (above 1600^{o}F) has a tendency to increase emissions due to the accelerated burning rate of the charge.

In-line incinerators - similar to the retort design in that the chambers share a common wall. In the in-line design the secondary chamber is not underneath the hearth, but is behind the primary chamber. This design is less effective than the retort in destroying the fluids from human and animal tissue.

Multi-chamber incinerators - multiple chamber incinerator designs consisting of separated primary and secondary chambers. The secondary chamber is generally located above the primary chamber with the two chambers having no common ceilings, hearth, or walls between them. The temperature in the secondary chamber has little or no influence on the primary chamber temperature. This design is preferable in processing non-tissue wastes.

BASIS FOR SUBCATEGORY BOUNDS: As regulation development proceeds, it may be beneficial to make subdivisions based on size, waste mix, or other criteria.

POLLUTANTS CONSIDERED FOR REGULATION: Section 129 pollutants.

FLOOR LEVEL OF CONTROL (EXISTING): No control. No justification has been found for good combustion practice as the floor.

REGULATORY ALTERNATIVES ABOVE FLOOR (EXISTING): See attached “Potential Incinerator Control Options” and “Subteam #1 Recommendations for Pollution Prevention Options”.

BEST CONTROLLED SIMILAR SOURCE (FLOOR-NEW): No units have been identified that achieve a level of emissions reduction that is superior to good combustion practice.

REGULATORY ALTERNATIVES ABOVE FLOOR (NEW): See attached “Potential Incinerator Control Options” and “Subteam #1 Recommendations for Pollution Prevention Options”.

STATUS OF DATA COLLECTION AND ANALYSIS: Have obtained some emission test reports on criteria pollutants and have requested additional test information for the Section 129 pollutants. However, the available data are incomplete and do not represent the scenarios we wish to evaluate. Have been unable to evaluate the information from the ICR respondents indicating they have information on the use of add-on emissions control devices.

ISSUES AND NEEDS:

Data - (1) Emissions data for the majority of sources for all 129 pollutants are limited. (2) There is uncertainty regarding the number of units in the less than 100 lb/hr grouping -- these units are not represented in the databases.

Subcategorization - Subcategories used herein (mass burn rate/hr) do not necessarily constitute a recommendation to EPA on subcategorization. Other ways of subcategorizing sources are possible, e.g., by use [human crematoria vs. non-human (animal waste) incinerators]. The best approach may be no subcategorization at all. Appropriate subcategories will be determined by emissions test results.

Emissions testing (special concerns) - Because of the frequent siting of the 500 lb/hr and under incinerators in residential and light commercial areas, we urge EPA to adopt the test plan recommended by Subteam #1 so as to determine the levels of 129 pollutants (especially metals, dioxins, and furans). The impact of dental amalgams containing mercury on mercury emissions from crematories, and the impact of varying amounts of bedding and “other” materials in animal waste incinerators, should be evaluated.

OTHER COMMENTS:

Control option recommendations - Subteam #1 recommends good combustion practices be adopted, including 1 second secondary chamber retention times and minimum secondary chamber temperatures of 1600 to 1800 ^{o}F based on design types as follows: 1600^{o}F for units 500 lb/hr and under, in-line and retort types; 1800^{o}F for units greater than 500 lb/hr, multi-chamber type. In addition, we recommend the use of combustion temperature controls.

Population estimates - We project that units in the less than 100 lb/hr grouping will decrease due to alternate methods of disposal such as composting. Units in the 100 to 500 lb/hr range will increase slightly due to an approximate increase of the human cremation rate of 4% per year until 2010 (based on statistics from the Cremation Association of North America). We expect the greater than 500 lb/hr unit population will remain static or decrease slightly over time.

POTENTIAL INCINERATOR CONTROL OPTIONS
Subteam #1
Pathological Waste Incinerators and Crematories

CONTROL OPTION	Potential for “Substantial” Emission Reduction											COMMENTS
	PM *		Op	SO_2	HCl	NOx	CO	Pb	Cd	Hg	D/F	
	f	t										
No control												Many incinerators are uncontrolled due to their small size, absence of regulations, and/or absence of demonstrated cost effective control technology.
Good combustion design and practice	✔	✔	✔				✔				✔	For example, control of temperature and feed rate and use of supplemental combustion/ secondary chamber. Other pollution prevention options are available (see attached document “Subteam #1 Recommendations for Pollution Prevention Options for Combustion Practice”).
Baghouse/ESP	✔	✔	✔					✔	✔	✔		There are no baghouse systems being manufactured for units this small. ESPs tend to be overly expensive for small incinerator applications. High temperatures may preclude the use of baghouses without an upstream scrubbing system or upstream temperature reduction device. Dioxin generation is a possibility.
Thermal oxidizer/afterburner			✔									Only applicable to single chamber units. Effectiveness with Section 129 pollutants unknown. Generates NOx and CO.

POTENTIAL INCINERATOR CONTROL OPTIONS (Continued)
Subteam #1
Pathological Waste Incinerators and Crematories

CONTROL OPTION	Potential for "Substantial" Emission Reduction											COMMENTS
	PM * f	PM * t	Op	SO_2	HCl	NOx	CO	Pb	Cd	Hg	D/F	
Cyclone/multiclone		✔	✔									Not very effective on these units because particle sizes are small.
Wet scrubber (low pressure or venturi) w/o water recycle		✔	✔	✔	✔							Will not provide significant improvement of emissions since the particle sizes on these units are small and good combustion efficiency is already being achieved. Acid gas formation could be a problem if water recycle is used in the presence of sulfur and chlorine. Some control of metals may occur (the presence of chlorine will enhance the removal of Hg). Creates water pollution
Dry acid gas/PM scrubbing system, including baghouse (DSI, dry sorbent injection system)	✔	✔	✔	✔	✔			✔	✔	✔	✔	Can be a highly effective control system, although cost may be prohibitive, especially for small units like these. Carbon injection for Hg control can be added at little incremental cost. Creates solid (possibly hazardous) wastes.

POTENTIAL INCINERATOR CONTROL OPTIONS (Continued)
Subteam #1
Pathological Waste Incinerators and Crematories

CONTROL OPTION	Potential for "Substantial" Emission Reduction											COMMENTS
	PM *		Op	SO_2	HCl	NOx	CO	Pb	Cd	Hg	D/F	
	f	t										
Semi-dry acid gas/PM scrubbing system (spray dryer and baghouse)	✔	✔	✔	✔	✔			✔	✔	✔	✔	Performs even better than DSI system, but costs are significantly higher. Carbon injection for Hg control can be added at little incremental cost. Creates water pollution and solid wastes.
Low-NOx burners, combustion chamber design, SNCR (ammonia injection)						✔						Applicability of low-NOx burners to these types of small incinerators is questionable due to high excess air requirements. Can create CO and NH_3 emissions.

*f = fine particulate matter; t = total particulate matter.

Subteam #1 Recommendations for Pollution Prevention Options for Combustion Practice

August 31, 1998

The following **good combustion practice** techniques are applicable to pathological waste incinerators and crematories: operator practices; maintenance knowledge; maintenance practices; residence time, temperature, turbulence; fuel/waste mix, quality, and handling (especially for pathological).

We recommend secondary combustion chamber residence times of 1 second and minimum secondary combustion chamber temperatures of 1600^{o}F to 1800^{o}F based on design types as follows: 1600^{o}F for units (retort, in-line) 500 lb/hr and under; 1800^{o}F for units (multi-chamber) over 500 lb/hr. In addition, we recommend the use of combustion temperature controls for all unit types.

Operator training requirements are appropriate for these units as well. Training content, hours, and qualifications should take into account that these units do not have complex methods of operation.

The following **metrics** are most suitable for these units: mass emissions/volume and, alternately, mass emissions/waste input. Mass emissions/volume of flue gas is comparable for all combustor sizes, provided auxiliary fuel is used. However, it is known that electrically heated crematories burn with equivalent or lower mass emissions/mass of waste input, yet higher mass emissions/volume of flue gas. Appropriate units for mass emissions/mass of waste input could be lb/100 lb burned.

Waste accounting and recordkeeping, work practice standards, waste constituent standards and de minimis levels would be applicable to non-tissue feed constituents. Certifications from suppliers of containers could be required, for example.

Several **MACT options** would be appropriate. These options are taken from the document "Non-consensus Recommendation to the Coordinating Committee on Options to be Incorporated into the ICCR MACT Rules; FINAL July 17, 1998." The options could be: a choice between the two metrics described above (Compliance Options A and B); a feed *de minimis* standard (option E), which would be most applicable to the non-tissue material feed; and/or a list of best operating practices determined to achieve comparable emission reductions to the numeric emission limit (option H).

SUBCATEGORY NAME: Drum Reclaimer Furnaces

ASSIGNED CAA SECTION (ICWI OR OSWI): Section 129 (ICWI).

GROUPINGS WITHIN SUBCATEGORY: None.

POPULATION STATISTICS:

ICCR Inventory Database - 38 facilities, 44 units
Trade group estimate - 55 units (national population)

Because in recent years steel drum production rates have remained unchanged, the number of drum reclamation furnaces is not expected to increase.

MATERIALS COMBUSTED: The drum reclaimer furnace is used to reclaim steel containers, most often 55-gallon drums, for reuse or to prepare them for recycling. Drums are prepared for cleaning by abrasive shot blasting by being processed through the furnace, where interior and exterior coatings and residues are burned or pyrolyzed. Drums must be empty as defined by RCRA prior to furnace processing, and thus, not subject to Section 3005 permitting requirements. Natural gas is most often fired as the primary fuel in drum furnaces.

COMBUSTION DEVICE: The typical drum reclaimer furnace is a semi-continuous tunnel furnace equipped with a high temperature thermal oxidizer. Heat inputs listed in the ICCR inventory database range from 1.2 MMBtu/hr to 15.6 MMBtu/hr.

BASIS FOR SUBCATEGORY BOUNDS: Due to the easy identification and substantial number of these units in the ICCR inventory database, their unique purpose, and the potential for emissions of Section 129 pollutants, they were subcategorized for further study. Drum reclaimer furnaces are distinct from parts reclaimer burnoff units because the drum reclaimer furnaces tend to be larger, with greater heat input, are semi-continuous rather than batch, and hazardous constituents potentially present in the drums may result in emissions different from those of parts reclaimers.

POLLUTANTS CONSIDERED FOR REGULATION: These include the complete set of Section 129 pollutants: PM, SO_2, CO, NOx, Pb, and HCl, dioxins/furans, Hg, and Cd. PM (RM5) emissions are likely to be fairly well-characterized, and there exist a number of State regulations on PM emissions from these furnaces. However, queries of the SURVEYV2.MDB database indicate that no HAPs data are available. The 112(c)(6) emissions inventory lists a 2,3,7,8-TCDD TEQ emission factor of 1.09E-07 lbs per 1000 drums burned.

FLOOR LEVEL OF CONTROL: Based on the inventory database, the floor for existing units is thermal oxidation. Practices such as ensuring that the drums are empty of all materials that can be reasonably removed by techniques other than combustion, and thermal oxidizer preheat prior to introducing drums into the furnace, are common and may also represent the floor, although this remains to be confirmed. Because the "best controlled similar unit" appears to be units in the inventory and survey databases that are controlled by thermal oxidizers, thermal oxidation would also be the floor for new units. (Although the inventory database lists a catalytic afterburner w/HX as a control device in use on one drum reclaimer furnace, we doubt that this control device is actually in use, and it does not appear in the survey database.)

REGULATORY ALTERNATIVES ABOVE FLOOR: Since the floor control does not control acid gases, a spray dryer or wet scrubber may be considered, depending on emissions of acid gases. Similarly, Cd and Pb are not controlled in a thermal oxidizer, and this suggests considering a fabric filter. In addition, sections of the Pollution Prevention *ad hoc* workgroup Good Combustion Practice guidelines may be applicable.

STATUS OF DATA COLLECTION AND ANALYSIS: Based on SURVEYV2.MDB, there appear to be no HAPs emission test data available for drum reclaimer furnaces. Subteam #4 is currently working with trade group representatives to further refine combustor description and population estimates and obtain existing emissions data on the other Section 129 pollutants.

ISSUES AND NEEDS: Subteam #4 wishes to express a concern on the paucity of emissions data for certain Section 129 pollutants.

OTHER COMMENTS: Recommendations for stack testing were submitted to the Coordinating Committee at its July 1998 meeting. A summary of control devices for drum reclaimer furnaces in the inventory and survey databases is presented below.

Air Pollution Control Devices for Drum Reclaimer Units listed in **SURVEY2.MDB**			
CODE	DESCRIPTION	Number	Percent
021	Direct Flame Afterburner	4	9%
022	Direct Flame Afterburner w/HX	1	2%
---	Units not listed	39	89%

Air Pollution Control Devices for Drum Reclaimer Units listed in **ICCRV2.MDB**			
CODE	DESCRIPTION	Number	Percent
000	None	8	18%
021	Direct Flame Afterburner	13	30%
020	Catalytic Afterburner w/HX	1	2%
---	Units not listed	11	50%

SUBCATEGORY NAME: Parts Reclaimer Burnoff Units

ASSIGNED CAA SECTION (ICWI OR OSWI): Section 129 (ICWI).

GROUPINGS WITHIN SUBCATEGORY:

Electrical winding reclaimer burnoff units
Non-PVC coated parts reclaimer burnoff units
PVC coated parts reclaimer burnoff units

POPULATION STATISTICS: ICCR Inventory database - 332 units. Subteam #4 estimates the national populations of the three groupings within the subcategory as follows:

Electrical winding reclaimer burnoff units ~300
Non-PVC coated parts reclaimer burnoff units ~1000
PVC coated parts reclaimer burnoff units ~50

MATERIALS COMBUSTED: This type of incinerator is used to reclaim metal parts for reuse in their current form. Coatings such as cured paint, plastisol, or varnish or unwanted parts such as plastic spacers or rubber grommets are burned off a wide variety of metal parts in these units. Plastisol coatings are comprised of polyvinyl chloride and phthalate plasticizer. Plastisol and paint both may contain heavy metal pigments. Metal parts fed to these primarily batch units include paint hooks/racks, electric motor armatures, transformer winding cores, and electroplating racks.

COMBUSTION DEVICE: Parts reclaimer burnoff units are typically small, batch, fossil fuel-fired units. The parts reclaimer burnoff units listed in the ICCR Inventory database list a range of heat inputs from 0.2 MMBtu/hr to 3.7 MMBtu/hr. They are often called burnoff ovens or pyrolysis units and often not recognized as "incinerators." Operations consist of loading the cold burnoff oven with metal parts, igniting the thermal oxidizer, if present, and main burner (both usually natural gas-fired), and allowing the combustible coating or part to pyrolyze into an fragile ash-like material (often over a period of hours) which may be then mechanically removed or abrasive-blasted off the metal part. Because of the wide variety of parts recycled in these units, facility size varies widely, from small electric motor repair shops to large automobile assembly plants.

BASIS FOR SUBCATEGORY BOUNDS: These units are subcategorized on the basis of similar purpose -- recovering a metal part for reuse in its current form. This places them in Section 129 rather than in Section 112 with the scrap metal recovery units, which are excluded by Section 129(g)(1)(A). They are kept separate from drum reclaimer furnaces because they tend to be smaller batch units and do not have the potential for burning RCRA hazardous wastes. However, Subteam #4 expects that at least some Section 129 pollutants are emitted from units in this subcategory.

POLLUTANTS CONSIDERED FOR REGULATION: Subteam #4 believes that there is a potential for emissions of all Section 129 pollutants from parts reclaimer burnoff units. Review of SURVEYV2.MDB indicates the existence of HAPs emissions data for at least two electrical winding reclaimer burnoff units (ICCR Facility IDs - 34017W091 and 550570416). Subteam #4 possesses a data summary of an old stack test of a PVC coated rack reclaimer burnoff unit that indicates the presence of HCl and organic compounds in stack emissions. In addition, any metals present in coating pigments also have the potential to be emitted.

FLOOR LEVEL OF CONTROL: Based on both the inventory and survey databases, the floor for parts reclaimer burnoff units is thermal oxidation. Practices such as thermal oxidizer preheat and the removal of excess combustible materials (e.g., paper, rope, cloth, and visibly loose coatings/parts) are common and may also represent the floor, although this remains to be confirmed. Because the "best controlled similar unit" appears to be units in the inventory and survey databases that are controlled by thermal oxidizers, thermal oxidation would also be the floor for new units. For electrical winding and PVC units, the floor for new units may also include wet scrubbers, although this has yet to be confirmed. (The inventory and survey databases also list some other control techniques, such as fabric filters, that are used sporadically in the industry and may represent the new unit floor for specific pollutants. However, a more detailed study of these devices is needed to determine their effectiveness on the range of units found in the parts reclaimer industry.)

REGULATORY ALTERNATIVES ABOVE FLOOR: The ICCR Inventory database lists a number of units controlled by a wet scrubber or a fabric filter in addition to a thermal oxidizer. The floor level of control (thermal oxidizer) does not control metals or acid gases, and control alternatives above the floor should examine scrubbers, spray dryers, and fabric filters. In addition, sections of the Pollution Prevention *ad hoc* workgroup good combustion practices (GCP) guidelines may be applicable.

STATUS OF DATA COLLECTION AND ANALYSIS: Based on Subteam #4 review of SURVEYV2.MDB, there appear to be at least two parts reclaimer burnoff units with HAPs emission data. These test reports are being obtained by EPA.

ISSUES AND NEEDS: Subteam #4 has recommended stack testing of two non-PVC coated parts reclaimers burnoff units and two PVC coated parts reclaimers burnoff units. Recommendations for stack testing were submitted to the Coordinating Committee at its July 1998 meeting. Subteam #4 also recommended an analysis of six cured coatings prior to processing in a parts reclaimer burnoff unit. These analyses have been incorporated into the Boiler Work Group's fuel/waste analysis program.

OTHER COMMENTS: A summary of control devices for parts reclaimer burnoff units in the inventory and survey databases is presented below.

Air Pollution Control Devices for Parts Reclaimer Units listed in **SURVEY2.MDB**			
CODE	DESCRIPTION	Number	Percent
019	Catalytic Afterburner	1	<1%
021	Direct Flame Afterburner	42	13%
022	Direct Flame Afterburner w/HX	6	2%
025	Staged Combustion	1	<1%
076	Multiple Cyclone w/o Flyash Reinjection (?)	2	<1%
086	Water Curtain (?)	3	1%
101	High Efficiency Particulate Air Filter	1	<1%
212	Air to Fuel Ratio Control	2	<1%
021 & 021	Direct Flame Afterburner & Direct Flame Afterburner	1	<1%
021 & 025	Direct Flame Afterburner & Staged Combustion	3	1%
021 & 028	Direct Flame Afterburner & Steam Injection	1	<1%
022 & 022	DF A.B. w/HX & DF A.B. w/HX	2	<1%
029 & 212	Low Excess Air & Air to Fuel Ratio Control	1	<1%
206 & 212	Low NOx Burners & Air to Fuel Ratio Control (?)	2	<1%
021 & 028 & 025	DF A.B. & Steam Inject & Staged Combustion	1	<1%
024 & 206 & 212	Mod. Furnace & Low NOx Burners & Ato F Ratio (?)	2	<1%
---	Approximate units not listed	261	79%

Air Pollution Control Devices for Parts Reclaimer Units listed in **ICCRV2.MDB**			
CODE(S)	DESCRIPTION	Number	Percent
000	none	38	11%
002	Wet Scrubber - medium efficiency	1	<1%
003	Wet Scrubber - low efficiency	1	<1%
020	Catalytic Afterburner w/HX	2	<1%
021	Direct Flame Afterburner	66	20%
022	Direct Flame Afterburner w/HX	4	1%
024	Modified Furnace/Burner Design	1	<1%
078	Baffle	1	<1%
099	Other Devices	1	<1%
101	High Efficiency Particulate Air Filter	1	<1%
256	No code description available (unknown)	1	<1%
021 & 002	Direct Flame Afterburner & Wet Scrubber - ME	1	<1%
021 & 003	Direct Flame Afterburner & Wet Scrubber - LE	1	<1%
021 & 004	Direct Flame Afterburner & Gravity Collector	1	<1%
021 & 006	Direct Flame Afterburner & unknown	3	1%
021 & 016	Direct Flame Afterburner & Fabric Filter - HT	1	<1%
021 & 028	Direct Flame Afterburner & Steam Injection	1	<1%
021 & 033	Direct Flame Afterburner & unknown	1	<1%
021 & 099	Direct Flame Afterburner & Other Devices	3	1%

Air Pollution Control Devices for Parts Reclaimer Units listed in **ICCRV2.MDB**			
CODE(S)	DESCRIPTION	Number	Percent
021 & 020 & 016	DF A.B. & Catalytic A.B. & Fabric Filter -HT	1	<1%
021 & 016 & 053	DF A.B. & Fabric Filter - HT & Venturi Scrubber	1	<1%
---	Approximate units not listed	201	61%

SUBCATEGORY NAME: Unclassified Metals-Related Incinerators

ASSIGNED CAA SECTION (ICWI OR OSWI): Sections 129 or 112.

GROUPINGS WITHIN SUBCATEGORY: Not applicable.

POPULATION STATISTICS: ICCR Inventory database - 212 units.

OTHER COMMENTS:

The unclassified subcategory represents units that have not been positively identified as drum reclaimer furnaces, parts reclaimer burnoff units, or scrap metal recovery units based on reviews of the inventory and survey databases. Survey responses have allowed identification of many previously unclassified units as parts reclaimer burnoff units, and it is likely that many currently unclassified units are probably parts reclaimer burnoff units.

Review of the current inventory of unclassified units indicates that many are "incinerators" associated with fabricated metal products industries such as appliance manufacturing, metal pipe coating, automotive parts manufacturing, electrical motor/transformer manufacturing, and pumps and compressors manufacturing. A closer review of the survey database may reveal whether these incinerators are parts reclaimer burnoff units or plant trash incinerators.

There are entries for semiconductor and electronics manufacturers, as well as ammunition manufacturers. If the units are used to recover the metals content of the electronic equipment or the brass components of ammunition, these could be considered scrap metal recovery units and would be excluded from Section 129.

A summary of control devices for unclassified metals-related units in the inventory and survey databases is presented below.

Air Pollution Control Devices for Unclassified Units listed in **SURVEY2.MDB**			
CODE	DESCRIPTION	Number	Percent
017	Fabric Filter - Medium Temperature	1	<1%
018	Fabric Filter - Low Temperature	6	3%
019	Catalytic Afterburner	1	<1%
021	Direct Flame Afterburner	19	9%
022	Direct Flame Afterburner w/HX	4	2%
025	Staged Combustion	1	<1%

Air Pollution Control Devices for Unclassified Units listed in **SURVEY2.MDB**			
CODE	DESCRIPTION	Number	Percent
076	Multiple Cyclone w/Flyash Reinjection	1	<1%
099	Other Devices	2	1%
001 & 021	Wet Scrubber HE & Direct Flame Afterburner	1	<1%
017 & 075	Fabric Filter MT & Single Cyclone	1	<1%
021 & 016	Direct Flame A.B. & Fabric Filter HT	1	<1%
021 & 017	Direct Flame A.B. & Fabric Filter MT	2	1%
022 & 050	Direct Flame A.B. w/HX & Packed Gas Absorp Col.	1	<1%
025 & 026	Staged Combustion & Flue Gas Recirc	1	<1%
099 & 200	Other Devices & Catalytic Oxidizer	2	1%
001 & 053 & 101	Wet Scrub HE & Venturi & HEPA Filter	2	1%
018 & 020 & 048	Fabric Filter LT & Cat A.B. w/HX & Active Carbon	1	<1%
021 & 028 & 212	DF A.B. & Steam Inject & Air to Fuel Ratio Control	1	<1%
---	Units not listed	164	77%

Air Pollution Control Devices for Unclassified Units listed in **ICCRV2.MDB**			
CODE	DESCRIPTION	Number	Percent
000	none	40	19%
001	Wet Scrubber - High Efficiency	1	<1%
010	Electrostatic Precipitator - High Efficiency	2	1%
013	Gas Scrubber, General	1	<1%
016	Fabric Filter - High Temperature	2	1%

Air Pollution Control Devices for Unclassified Units listed in **ICCRV2.MDB**			
CODE	DESCRIPTION	Number	Percent
021	Direct Flame Afterburner	28	13%
025	Staged Combustion	1	<1%
070	Sodium-Alkali Scrubbing	2	1%
099	Other Devices	1	<1%
255	unknown	4	2%
021 & 008	Direct Flame A.B. & Centrifugal Collector - ME	1	<1%
021 & 016	Direct Flame A.B. & Fabric Filter - HT	1	<1%
022 & 009	DF A.B. w/HX & Centrifugal Collector - LE	1	<1%
---	Units not listed	127	60%

SUBCATEGORY NAME: Potential Section 129 Solid Mixed Feed Boilers

ASSIGNED CAA SECTION (ICWI OR OSWI): Section 129 Boilers (TBD)

POPULATION STATISTICS: There are approximately 322 boilers identified in the EPA ICR Survey Version 2.0 database that may fall into this subcategory.

MATERIAL COMBUSTED: Various non-fossil Section 129 solid materials. These materials are generally co-fired with other non-fossil materials or fossil fuels.

COMBUSTION DEVICE: All types of boilers are used, including bubbling and circulating fluidized beds, cell-tubes, cyclone-fired, dutch ovens, fire tubes and water tubes, stokers, wet and dry bottom units, wall-fired and tangentially-fired and package and field-erected units.

BASIS FOR SUBCATEGORY BOUNDS: This subcategory includes all boilers that fire above a minimum percentage of Section 129 solid materials. These boilers may potentially have different controls than the section 129 liquid materials due to the difference in the physical state of fuels burned.

POLLUTANTS CONSIDERED FOR REGULATION: Section 129 Pollutants

FLOOR LEVEL OF CONTROL: Further analysis is being done.

Existing Sources. At this time, the preliminary MACT floor level of control is equivalent to the emission limit for boilers in this subcategory controlled with fabric filters (or an equivalent control technology) for controlling metallic HAPs, scrubbers (or an equivalent control technology) for reducing inorganic HAPs, and good combustion practices for reducing organic HAPs. These results are based on preliminary control techniques rankings for all boiler subcategories. Further analysis will look at combinations of controls.

New Sources. Same results as existing sources. In addition, the preliminary MACT floor for new sources for controlling mercury is scrubbers. These results are based on preliminary control techniques rankings for all boiler subcategories. Further analysis will look at combinations of controls.

REGULATORY ALTERNATIVES ABOVE THE FLOOR: No regulatory alternatives have been identified for controlling metals and inorganic HAPs. Alternatives above the MACT floor level of control for new and existing sources are carbon absorption for control of organic HAPs and mercury.

STATUS OF DATA COLLECTION AND ANALYSIS: An Information Collection Request (ICR) was sent to facilities with boilers burning potential 129 materials. Responses provided information on the control techniques being used on the boilers in this subcategory. Emission test reports were gathered on boilers burning the materials combusted. However, only minimal data was obtained for some of the section 129 pollutants and HAPs. EPA has requested additional test reports from ICR respondents, but data gaps are expected to remain.

ISSUES AND NEEDS: Further testing of non-fossil materials and control devices is recommended in order to analyze emissions and set emission limits. A definition of non-hazardous solid waste is needed. The level of Section 129 materials that trigger regulation under Section 129 needs to be determined. The Boiler Work Group needs to further analyze the boilers and their control equipment in this subcategory to determine if more refined subcategories are needed.

OTHER COMMENTS: None.

SUBCATEGORY NAME: Potential Section 129 Liquid Mixed Feed Boilers

ASSIGNED CAA SECTION (ICWI OR OSWI): Section 129 Boilers (TBD)

POPULATION STATISTICS: There are approximately 153 boilers identified in the EPA ICR Survey Version 2.0 database that may fall into this subcategory.

MATERIAL COMBUSTED: Various non-fossil Section 129 liquid materials. These materials are generally co-fired with other non-fossil materials or fossil fuels.

COMBUSTION DEVICE: All types of boilers are used, including bubbling fluidized beds, cell-tubes, cyclone-fired, dutch ovens, fire tubes and water tubes, stokers, wet and dry bottom units, wall-fired and tangentially-fired and package and field-erected units.

BASIS FOR SUBCATEGORY BOUNDS: This subcategory includes all boilers that fire above a minimum percentage of Section 129 liquid materials but no Section 129 solid materials. These boilers may potentially have different controls than the section 129 solid materials due to the difference in the physical state of fuels burned.

POLLUTANTS CONSIDERED FOR REGULATION: Section 129 Pollutants

FLOOR LEVEL OF CONTROL: Further analysis is being done.

Existing Sources. The preliminary MACT floor level of control is equivalent to the emission limit for boilers in this subcategory controlled with ESPs (or an equivalent technology) for reducing metallic HAPs, scrubbers (or an equivalent control technology) for reducing inorganic HAPs, and good combustion practices for reducing organic HAPs. These results are based on preliminary control techniques rankings for all boiler subcategories. Further analysis will look at combinations of controls.

New Sources. The preliminary MACT floor level of control is equivalent to the emission limit for boilers in this subcategory controlled with fabric filters (or an equivalent control technology) for reducing metallic HAPs, gas absorbers (or an equivalent control technology) for reducing inorganic HAPs, good combustion practices for reducing organic HAPs, and scrubbers for reducing mercury. These results are based on preliminary control techniques rankings for all boiler subcategories. Further analysis will look at combinations of controls.

REGULATORY ALTERNATIVES ABOVE THE FLOOR: Alternatives above the MACT floor level of control are emission limits for boilers controlled with fabric filters (or an equivalent control technology) for metals, and carbon adsorption for organic HAPs and mercury. No above the floor alternatives have been identified for inorganic HAPs.

STATUS OF DATA COLLECTION AND ANALYSIS: An Information Collection Request (ICR) was sent to facilities with boilers burning potential 129 materials. Responses provided information on the control techniques being used on the boilers in this subcategory. Emission test reports were gathered on boilers burning the materials combusted. However, only minimal data was obtained for some of the Section 129 pollutants and HAPs. EPA has requested additional test reports from ICR respondents, but data gaps are expected to remain.

ISSUES AND NEEDS: Further testing of non-fossil materials and control devices is recommended in order to analyze emissions and set emission limits. A definition of non-hazardous solid waste is needed. The level of Section 129 materials that trigger regulation under Section 129 needs to be determined. The Boiler Work Group needs to further analyze the boilers and their control equipment in this subcategory to determine if more refined subcategories are needed.

OTHER COMMENTS: None.

Attachment 5

Boiler Work Group Presentation on Preliminary MACT Floors For Natural Gas and Fuel Oil-Fired Boilers

Fossil Fuel Preliminary Subcategories and MACT Floor

Boiler Work Group

9/16/98

Overview to MACT Floor

- **Key Definitions and Concepts**
- **Subcategorization**
- **Approach to MACT Floor**
- **Review of ICCR Boiler Inventory DB V. 3.0**
- **Review of ICCR Emissions DB**
- **Review of State Regs/Permits and RACT/BACT/LAER DB**
- **Final Conclusions**
  - **No MACT Floor For Controls**
  - **No HAP Emission Limits**

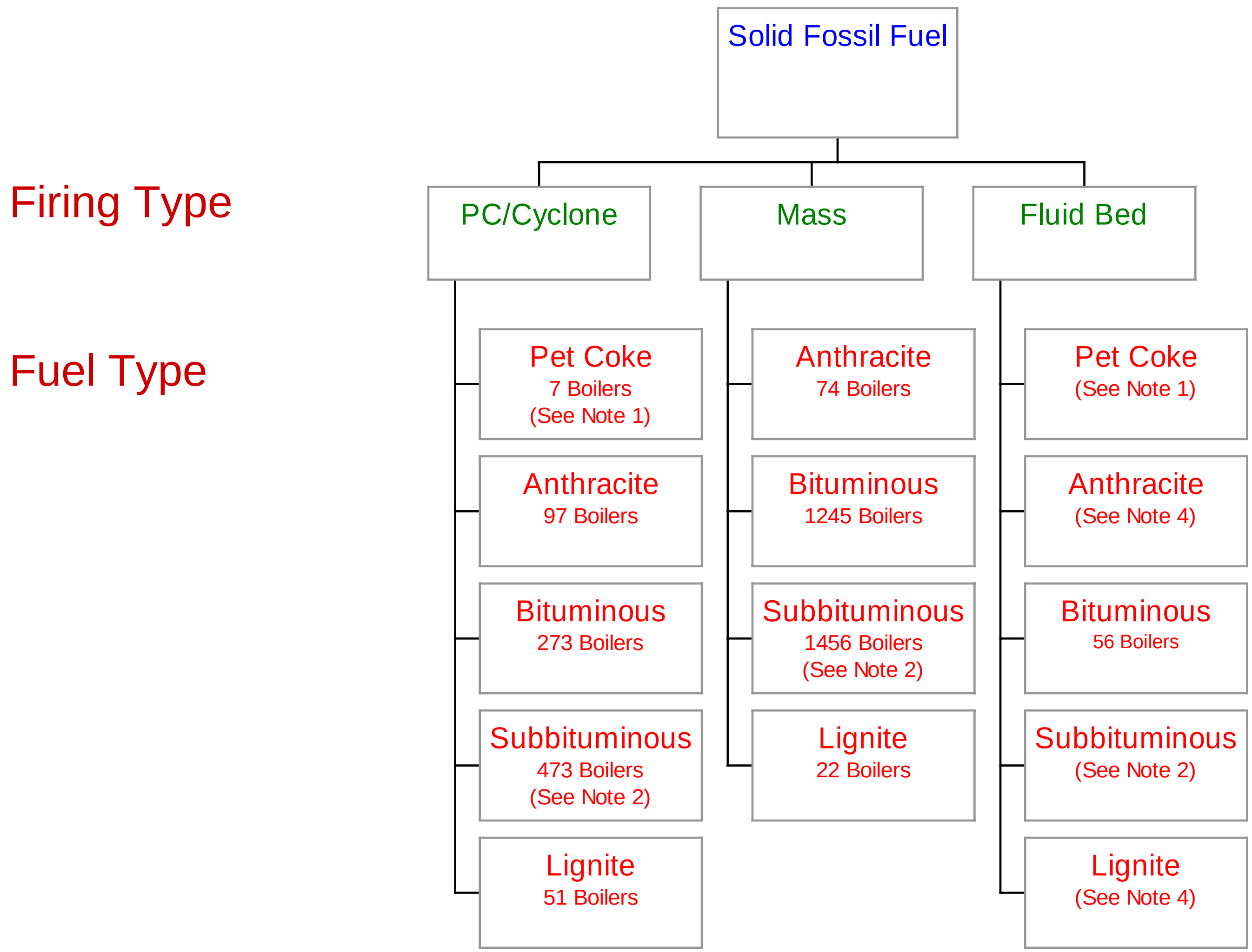
Key Definitions

- Boiler
- Gas
  - Pipeline Gas/Wellhead Gas/LPG
  - Gas Derived From Oil, Petroleum, Petrochemical Processing - Not a Consensus
- Oils - Distillate and Residual
- Coal
  - Includes Anthracite, Lignite, Bituminous and Sub Bituminous, Petroleum Coke

Subcategories

- Gas
  - By Fuel - Similar Burner Designs
- Oils
  - By Fuel - Similar Burner Designs
- Solid Fossil Fuels
  - See Chart

Sub Categories



Note 1 34 Petroleum Coke Boilers were identified in the Inventory Database with no boiler type

Note 2 33 Subbituminous Boilers were identified in the Inventory Database with no boiler type

Note 3 404 Boilers were identified in the Inventory Database with no boiler type or fuel type

Note 4 No Boilers were identified in the Inventory Database for these types; These could exist

MACT Determination Methodology

- Use Subcategories as Described
- Use Inventory DB V.3 to determine MACT Controls
- Use Emissions DB to Determine HAP Emission Limits
- Review RACT/BACT/LAER DB for Controls/HAP Limits
- Used top 6% of Technology as First Cut
- Review Databases for
  - Good Control Practices
  - Pollution Prevention
- Burn only Fossil Fuels.
- Only Specified Control/No Control Data Used in Technology Cutoffs

Preliminary MACT Floor Determination for Fossil Fuel-Fired Boilers - V.3 DB

- **Gaseous Fossil Fuel Subcategory**
  - **42,582 boilers total**
  - **18,321 boilers with control information**
  - **177 boilers (0.97 %) may have applicable add-on controls**
  - **Some controls not believed to be applicable for boilers firing gaseous fuels**
- **Conclusion: Considering only boilers with control information or those specifying ‘no control’ - < 6% of units have add-on control. <u>No MACT Floor for Controls.</u>**

Preliminary MACT Floor Determination for Fossil Fuel-Fired Boilers - V. 3 DB

- **Liquid Fossil Fuel Subcategory**
  - **Unheated fuel (Distillate Oil)**
    - **6604 boilers total**
    - **2623 boilers with control information**
    - **70 boilers (2.68 %) may have applicable add-on controls**
- **Conclusion: Considering only boilers with control information or those that specify 'no control' - <6% of units have add-on control. <u>No MACT Floor for Controls.</u>**

Preliminary MACT Floor Determination for Fossil Fuel-Fired Boilers -V. 3 DB

- **Liquid Fossil Fuel Subcategory**
  - **Heated fuel (Residual Oil)**
    - **7945 boilers total**
    - **4810 boilers with control information**
    - **264 boilers (5.50 %) may have applicable add-on controls**
    - **Some controls not believed to be applicable for boilers firing liquid fuels.**
- **Conclusion: Considering only boilers with control information or those that specify 'no control' - <6% of units have add-on control. <u>No MACT Floor For Controls.</u>**

Preliminary MACT Floor Determination for Fossil Fuel-Fired Boilers

- **Coal**
  - **Initial thinking to split by firing method:**
    - **Pulverized fuel/cyclone**
    - **Mass feed/stoker**
    - **Fluidized bed**
  - **Then Split By Fuel Type**
  - **MACT Floor Not Determined**
    - **Further refinement being evaluated**

Emissions DB Conclusions - Gas

- Variable Data
- Percent of Data Not Representative of Large Enough Sector
- No Data to Evaluate Control Efficiencies
- Conclusion:
  - No Recommendation for HAP Emission Limit or Control Based on HAP Emission Limit

Permit/Regs DB Conclusions - Gas

- **Permit Limit Information**
  - **17 Gas Fired Units of >42,000 had Permit Limits**
  - **<u>No MACT Floor/Emission Limits Based On Permits</u>**
- **State Air Regulations**
  - **No State Air Emission Regs. On HAPs**
  - **<u>No MACT Floor/Emission Limit Based On State Regs</u>**
- **RACT/BACT/LAER Database**
  - **No Gas Fired Units Had Permit Limits**
  - **<u>No MACT Floor/Emission Limits Based On RACT/BACT/LAER Database</u>**

Emissions DB Conclusions - Oil

- Data Inadequate to Identify Best Performing Group or HAPs Limits
- Some Coal Fired Controls Used on Oil Fired Systems
- Variable Data
- Conclusion:
  - No Recommendation for HAP Emission Limit or Control Based on HAP Emission Limit

Permit/Regs DB Conclusions - Oil

- **Permit Limit Information**
  - **15 Fired Units of >14,000 had Permit Limits**
  - **<u>No MACT Floor/Emission Limits Based On Permits</u>**
- **State Air Regulations**
  - **No State Air Emission Regs. On HAPs**
  - **<u>No Mact Floor/Emission Limit Based On State Regs</u>**
- **RACT/BACT/LAER Database**
  - **<0.1% of Oil Fired Units Had Permit Limits**
  - **<u>No MACT Floor/Emission Limits Based On RACT/BACT/LAER Database</u>**

Emissions DB Conclusions - Coal

- **Need More Work On Coal Data**
  - **Complex and Multiple combustion Combinations**

Rationale For MACT Floor - GCP/P2

- GCP Techniques Evaluated - Gas/Oil
  - Fuel/Air Ratio
  - Maintenance
  - Tune-Up (State Regulations)
- Pollution Prevention (P2)
  - Boiler Efficiency Considerations
- NON CONSENSUS On No MACT Floor Based On GCP/P2

Emission Limitations

- **Based On:**
  - **State Air Emission Limits (Permits/Regs)**
  - **ICCR Emission Database**
  - **RACT/BACT/LAER DB**
- **No Emission Limits Recommendations**

Fossil Fuel Boiler MACT Floor Conclusions

Subcategory	CONTROLS	HAP Limitation
Gas Fired Boilers	No MACT Floor	None
Oil Fired Boilers	No MACT Floor	None
Coal Fired Boilers	To Be Determined	To Be Determined

Attachment 6

Paper on Preliminary MACT Floors For Natural Gas and Fuel Oil-Fired Boilers (Closure Item)

Preliminary Subcategories and MACT Floor Determination for Gas, Distillate Oil and Residual Oil Fired Boilers

Boiler Work Group
Of the
Industrial Combustion Coordinated Rulemaking (ICCR)
Federal Advisory Committee

September 3, 1998

TABLE OF CONTENTS

<u>Section</u>

TABLE OF CONTENTS (Continued)

<u>Section</u>

EXECUTIVE SUMMARY

The Boiler Work Group (BWG) reached consensus that, based on the data reviewed and the assumptions identified below, no MACT Floor can be identified at this time for oil and gas. In this discussion and presentation, No MACT Floor means:

No group corresponding to the best performing 12% of existing sources could be identified by reviewing the following information:

- Existing add-on controls that may reduce HAPs
- Existing emissions data, air regulations, and air permit limitations for HAPs

That is, NO MACT FLOOR FOR OIL AND GAS FIRED BOILERS.

However, the BWG did not reach consensus on whether:

- Good combustion practice (GCP) should be incorporated into the MACT Floor at this time and,
- Gaseous fuel derived from the processing of crude oil, petroleum or petrochemicals should be categorized with natural gas.

EPA should further consider how these two issues and other issues affect MACT floor determinations, if at all.

The Boiler Work Group (BWG) has determined preliminary subcategories for natural gas, oil (distillate and residual) and coal fossil fuel fired boilers. Further, it has identified the preliminary MACT floor for gas and oil fossil fuel fired boilers. The BWG recommends that the Coordinating Committee of the ICCR FACA forward these determinations and associated rationale to the EPA.

Fossil Fuel Fired Boiler Subcategories

The BWG has determined that the following subcategories should be used for fossil fuel fired boilers:

- Natural Gas (Includes wellhead gas, pipeline gas, LPG) NOTE: there was not a BWG consensus to include Gaseous Fuels derived from processing of crude oil, petroleum or petrochemicals in the Natural Gas subcategory
- Oils
  - Unheated or Distillate Oils
  - Heated or Residual Oils
- Coal (Solid Fossil Fuel)

- Fluidized Bed Boilers which would be further divided into the following fuel groups:
  - Anthracite, Bituminous, Subbituminous, Lignite, Petroleum Coke
- Mass Fired / Stoker Boilers which would be further divided into the following fuel groups:
  - Anthracite, Bituminous, Subbituminous, Lignite
- Pulverized / Cyclone Boilers which would be further divided into the following fuel groups:
  - Anthracite, Bituminous, Subbituminous, Lignite, Petroleum Coke

The workgroup determined for coal that to describe boilers by firing type and then by fuel type was necessary to encompass the different combinations that may have an effect on HAP emissions.

The BWG recommends that the ICCR Coordinating Committee forward to the EPA these subcategories for the above listed fuel groups. The BWG recognizes that the final subcategories for any MACT standards established for existing fossil fuels may be different than those established for the purposes of a final MACT floor regulation since other information and data reviews may occur between now and the final rule.

MACT Floors for Fossil Fuel Boilers

The BWG reached consensus on MACT Floors for the gas and oil fossil fuel fired boilers in the subcategories stated above. The BWG reached consensus that based on the data reviewed and the assumptions shown in this document, NO MACT FLOOR can be identified at this time for oil and gas fired boilers.

MACT floors for solid fossil fuel (coal) boilers were not fully developed by the boiler workgroup. The floors will probably include some form of particulate control. Further evaluation of both the emission database and inventory database is needed to determine what the floors should be.

The BWG recommends that the Coordinating Committee forward this NO MACT FLOOR determination for oil and gas to the EPA.

Rationale for Fossil Fuel Subcategories

Natural Gas Boilers

Basically Natural Gas Boilers (including wellhead gas, pipeline gas, LPG, and Gaseous Fuels Derived from processing of crude oil, petroleum or petrochemicals) have similar burner design. Whether fire tube or water tube boilers, combustion characteristics for HAPs were assumed to be defined by the fuel rather than the burner.

Oil Fired Boilers

Like gas fired boilers, the preponderance of oil fired boilers have similarly designed burners. In general they atomize the fuel into the firing chamber by means of steam, air or a mechanical device. Again, like gas, the combustion process is fuel dependent rather than boiler dependent. Therefore, oil fired systems were divided into two subcategories: distillate (unheated) oil and residual (heated) oil.

Coal Fired Boilers

For the solid fossil fuel fired boilers two main factors were considered for the subcategories. These were basic boiler design and fuel type. The boiler designs were split into three basic firing types: pulverized / cyclone, mass fired, and fluidized bed. Each of these firing types could have an effect on HAP formation due to the differences in boiler and fuel feed design. After considering the firing type, the fuel type must be considered. The ASTM standard fuel definitions were used: anthracite, bituminous, subbituminous, and lignite. Petroleum coke was also considered as a fuel type. The fuel type also plays a key role in boiler design that could effect HAP formation and emissions.

Rationale for MACT Floor Determination

The BWG identified the MACT floors for existing natural gas and oil subcategories in accordance with the provisions for MACT included in Section 112(d) of the Clean Air Act, as amended in 1990. In order to identify the best performing group of sources and determine the MACT floors, the BWG reviewed the following available information related to control devices and HAPs emissions for existing boilers:

- Existing add-on controls that may reduce HAPs,
- Existing good combustion practices that may reduce HAPs,
- Existing emissions data, and
- Existing air regulations, air permits and RACT/BACT/LAER databases for HAPs limitations.

The BWG reviewed ICCR Inventory Database version 3.0 to assess the prevalence of existing add-on controls for gas and oil fired systems. The BWG determined that the average of the best performing 12 percent could be estimated by first assessing whether at least 6 percent of the boilers in a subcategory had add-on controls. Therefore, the BWG set its add-on control cutoff at 6 percent for oil and gas fired boilers. Using this cutoff standard, gas fired and oil (distillate and residual) fired systems did not have add-on controls in the database that exceeded the 6 percent level. The conclusion was that there was No MACT Floor for controls in these three subcategories.

MACT floors for controls for solid fossil fuel (coal) boilers were not fully developed by the boiler workgroup. The floors will probably include some form of particulate control. However, further evaluation of both the emission database and inventory database is needed to determine what the floors should be and whether or not it is appropriate for acid gas controls to be part of the floors.

The BWG also reviewed Good Combustion Practices (GCP) for gas and oil fired boiler systems. Issues like air/fuel ratios and maintenance practices were studied. However, based on the information reviewed thus far some of the Boiler Work Group believe that good combustion practices should not be included in the MACT Floor for existing gas or oil fired boilers. However, this was not a consensus decision. It was thought by some that combustion practices like air to fuel ratios may, in fact, concurrently control HAP emissions even though that may not have been the intended reason for the control.

Emission data was reviewed to determine if there were HAP limits that needed to be regulated for MACT floor purposes. The BWG reviewed the emissions database for boilers, state permit limits, state regulation limits and the RACT/BACT/LAER databases. The BWG concluded that based on the information in these databases there is insufficient information to identify a MACT floor for emission limits. Therefore, again, there is NO MACT FLOOR for the oil and gas subcategories. That is, there is insufficient information to establish HAP emission limitations or HAP emission reduction targets as a part of the MACT floor for these subcategories.

1.0 INTRODUCTION

It was the Boiler Work Group's (BWG) intent to determine subcategories and thence the MACT Floors for those subcategories. The BWG determined the subcategories for natural gas, oil (distillate and residual) and coal fuels. The BWG was successful in determining a MACT Floor for natural gas and the oils. Further work will have to be done in order to determine the MACT floor for coal.

This paper documents the results of the processes to reach these conclusions. In general, the Fossil Fuel subgroup performed the majority of the study and presented its results to the BWG. Consensus was obtained in the BWG with the exception of gaseous fuels derived from processing of crude oil, petroleum or petrochemicals being included in the definition of natural gas and the determination that there were no good combustion practices (GCP) that controlled HAPs.

Below is a description and discussion of the following topics that led to the final subcategorization and MACT floor determinations:

- Subcategorization methodology and rationale
- Review of the Boiler Inventory Database (V 3.0), state regulation and permit databases for MACT Floor control determination
- Review of the Emissions Database and state regulation and permit databases for HAP emission limit determination
- Review of Good Combustion Practices to determine if they could be considered in the MACT Floor determination.

2.0 SUBCATEGORIES FOR FOSSIL FUEL BOILERS

2.1. <u>Key Definitions</u>

There are several key definitions to be considered when beginning to subcategorize fossil fired boilers.

2.1.1 Boiler

Boiler means an enclosed device using controlled flame combustion and having the primary purpose of recovering and exporting useful thermal energy in the form of hot water, saturated steam or superheated steam. The principal components of a boiler are a burner, a firebox, a heat exchanger, and a means of creating and directing gas flow through the unit. A boiler's combustion chamber and primary energy recovery section(s) must be of integral design (i.e., the combustion chamber and the primary energy recovery section(s), such a as waterfall and superheaters, must be physically formed into one manufactured or unit assembled unit. (A unit in which the combustion chamber and the primary energy recovery section(s) are joined only by ducts or connections carrying flue gas is not integrally designed; however secondary energy recovery equipment (such as economizers or air preheaters) need not be physically formed into the same unit as the combustion chamber and the primary energy recovery section.) Only stand-alone boilers are covered by this definition; waste heat boilers, which are associated with stationary gas turbines or engines, are excluded. (From the *Regulatory Alternatives Paper* by the Incinerator Work Group submitted to the ICCR Coordinating Committee July, 1998.)

2.1.2 Natural gas

The natural gas category includes:

- Standard Definition of Natural Gas: The definition for Natural Gas was taken from the NSPS Rules in 40 CFR 60.41 b: a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or (2) liquid petroleum gas, as defined by the American Society for Testing and Materials in ASTM D1835-82, "Standard Specification for Liquid Petroleum Gases". For all practical purposes, natural gas includes wellhead gas which is gas straight from the ground containing principally methane, hydrogen, carbon and oxygen.

- Liquid Petroleum Gas(LPG): LPG is propane and/or butane often with small amounts of propylene and butylene sold as a pressurized liquid. LPG is also used by boilers for ignition fuel and as a standby fuel. For purposes of the MACT Floor determination, LPG is included with natural gas as given in the definition above.

Gaseous Fuels derived from processing of crude oil, petroleum or petrochemicals: There was not a consensus in the BWG on adding this to the definition of natural gas. The Petroleum Environmental Research Forum Project 92-19 (PERF data) found no significant difference in air toxic emissions between burning natural gas, as defined above, and these process derived gaseous fuels. Enclosed in Appendix 1 there is a paper entitled "Rationale for Broad Definition of Gaseous Fuels" which supports the argument of incorporating Gaseous fuels derived from processing of crude oil, petroleum or petrochemicals into the definition of Natural Gas.

However, at this time, because of not being able to review and digest the information, the BWG did not come to consensus on this definition and is deferring the decision of the incorporation of these process derived gaseous fuels with natural gas to the EPA.

2.1.3 Oils

Oils can be divided into two categories:

- Distillate Oil (also called unheated oil): Fuel oils that comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Material in ASTM D396-78, Standard Specifications for Fuel Oil. (40 CFR 60.41 b)

- Residual Oil (also called heated oil): Crude oil, and all fuel oil numbers 4,5, and 6 as defined by the American Society of Testing and Materials in ASTM D-396-78, Standard Specifications for Fuel Oils. (40 CFR 60.41 b)

2.1.4 Coal

The coal definition is the same as that from 40 CFR 60.41b (NSPS Subpart Db) – Coal means all solid fuels classified as anthracite, bituminous, sub-bituminous, or lignite by the American Society of Testing and Materials in ASTM D388-77, Standard Specification for Classification of Coals by Rank, coal refuse, and petroleum coke. Coal-derived synthetic fuels, including but not limited to solvent refined coal, gasified coal; coal-oil mixtures are also included in this definition.

2.2 Subcategorization

The Boiler Work Group established subcategories for fossil fuel fired boilers to incorporate factors that may affect the HAP emissions from those units and/or the viability of control techniques that may reduce HAP emissions from those units. The Work Group determined that the fuel type and firing method are the key factors that affect HAP emissions and the viability of controls.

Gas, oil and coal were initially divided into categories due to the nature of constituents making up the fuel type and their method of handling. For instance gas is primarily methane, hydrogen, carbon and oxygen. However, coal may contain metals and more complex hydrocarbons. Coal is burned in a different manner than either gas or oils. Therefore, it was determined to initially separate these three fuel types.

Further discussion of the rationale for subcategorization is provided in the sections below:

2.2.1 Gas Fired Systems

Gas fired systems were left as a single subcategory for several reasons. The first was based on the overall emissions from those types of boilers. The emissions on all types of gas fired boilers, although variable, were generally very low. Second, the controls on boilers generally were not designed to control HAP emissions. Third and perhaps most important is that the burner design on gas fired systems is essentially the same for various types of gas fired boilers. It consists of an air and gas mixing system. The burner is designed to guarantee adequate mixing for good stoichiometric combustion.

2.2.2 Distillate Oil Fired Systems

Distillate Oil systems were likewise left as a single subcategory for essentially the same reasons as gas fired systems. The oils are atomized in the burner in several manners (air, steam or mechanical). The purpose of atomization, no matter what the method, is to better mix the fuel with the air. It was assumed, like gas, that distillate oil because of the similarity of the fuel mixing burners and the effectiveness of the burners, that combustion characteristics and therefore the HAPs emissions should not be appreciably noticeable between boiler types within the Distillate Oil fired category.

2.2.3 Residual Oil Fired Systems

All residual oils or heavy oils (No. 4 and above) are generally heated prior to introduction in to the burner. Residual oils, like distillate oils use the atomization method for injection of the fuel into the firing chamber. Because of similar firing designs among oil burners, they were left as a single category.

2.2.4 Coal

2.2.4.1 Solid Fossil Fuels (Coal). The ASTM fuel types were chosen for the further subcategorization. Petroleum coke was also included as a fuel type. Fuel types vary by their carbon content and other factors like moisture content, ash content, and BTU content to name a few. All of these factors effect boiler design and can affect HAP formation and emissions

ASTM Standard D388 - 77 is entitled "Standard Classification of Coals by Rank." The main ranks of coal in this standard are anthracite, bituminous, subbituminous, and lignite. Each of these major ranks is broken down into at least two sub-ranks. The boiler workgroup believes that there is no need to break the ranks into the sub-ranks for subcategories. Fuels are ranked by carbon content if the carbon content is greater that 69% and by BTU content for all other fuels. Carbon content is generally inversely proportional to volatile content. This factor plays a key role in boiler size (e.g., larger for higher volatility) and configuration.

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Coal refuse means any by-product of coal mining or coal cleaning operations with an ash content greater than 50 percent (by weight) and a heating value less than 6,000 Btu per pound (Btu/lb) on a dry basis.

Petroleum Coke is a carbonaceous solid produced from coal, petroleum, or other materials by thermal decomposition.

Many other factors effect boiler design and vary with fuel type. These include ash content and ash characteristics, and moisture content. All of these factors are taken into account when sizing a boiler and designing the heat transfer surfaces. As the design changes to accommodate the differences in the fuel, many things in the boiler change including the temperature profile which could effect HAP formation and emission rates. The boiler designs established for subcategories are the following: pulverized coal/cyclone, mass fired, fluidized bed.

2.2.4.2 Solid Fuel Boiler Types. Solid fossil fuels were also subdivided into boiler types. Three main boiler types were determined to be appropriate for the subcategories. The types are fluidized bed boilers, mass feed or stoker boilers, and pulverized coal or cyclone boilers. Each of these boilers has a unique firing system that could result in different HAP emissions.

Many factors must be considered during boiler design. One of the main factors is where and how the fuel is introduced into the furnace. This main factor lead to the decision by the boiler workgroup to first subcategorizes by boiler types. The types are fluidized bed boilers, mass fired / stoker boilers, and pulverized / cyclone boilers.

Each boiler type that was identified for subcategorization has a different firing system. Pulverized and cyclone boilers fire the fuel in suspension while in mass fired boilers some portion of the combustion takes place on the furnace floor on a grate. The fluidized bed boilers burn fuel in an aerated mass with limestone. Each of these firing types leads to different temperatures of combustion and boiler temperature profiles that can result in different HAP formation and emission rates.

Pulverized Coal/Cyclone

Pulverized coal boilers burn coal in suspension by pulverizing the coal and injecting it into the boiler with a transport air stream. In general, a low percentage of ash drops out as bottom ash (approximately 20%), with the remainder passing through the boiler as flyash, dropping out in hoppers or particulate collection devices. Pulverized coal fired boilers can be dry bottom or wet bottom. Wet bottom boilers operate at a higher furnace temperature and use coal with properties that allow a portion of ash to be removed from the furnace in the molten state. Dry bottom boilers operate at a lower temperature and use coal with properties, which do not create molten slag in the furnace. While there could be differences in HAP emissions from dry bottom vs wet bottom boilers; there is not adequate data on which to differentiate between those designs for MACT floor purposes.

Cyclone boilers burn crushed coal in cyclones prior to entering the boiler furnace. The cyclones operate at a high temperature, which allows a significant quantity of ash to be removed in the molten state.

In general, HAP emission rates are believed to be similar for pulverized coal and cyclone boilers for MACT floor purposes.

Mass Fired

Mass fired boilers include mass feed stokers, spreader stokers, and underfeed stokers. These types of boilers are characterized by the use of larger sized coal (about 2x0 top size) wherein most of the coal is burned on the grate. This feature results in most of the coal ash being removed as bottom ash (at least 80%), with the remainder passing through the furnace as flyash, dropping out in hoppers or particulate collection devices. Some stoker-fired boilers also reinject cinders or flyash into the furnace in order to reduce unburned carbon losses. Excess air levels in general are higher for mass fired boilers vs pulverized coal/cyclone units due to the greater difficulty in obtaining proper fuel/air mixing with mass fired units.

Fluidized Bed

Fluidized bed boilers operate with either a bubbling bed or circulating bed. In both cases, the upward velocity of air through the bed causes a suspension of the fuel and inert matter or limestone. Circulating fluid bed units operate with a high furnace velocity, which entrains particulates and allows recirculation back into the bed for increased carbon burnout.

An important design parameter is the type of fuel in combination with the boiler type. As an example, a bituminous stoker is designed much differently than a pulverized bituminous unit. The result could be different HAP emissions from the same fuel. All of the above reasons lead to the subcategories being established based on firing type in combination with fuel type.

3.0 APPROACH AND RATIONALE FOR MACT FLOORS

3.1 General Approach to MACT Floor Analysis

The BWG decided to make some basic assumptions in order to determine the MACT floor. These assumptions are as follows:

- First, this is a preliminary MACT Floor determination for these fossil fuels. This is by no means a final review since testing has not been performed and the data is still being analyzed.

- The categories are based on fuel type (gas, liquid and solid) and the subcategories are broken out as described above.

- The data used for the MACT floor determination for controls is the EPA Boiler Inventory Database Version 3.0.

- The data that was reviewed for this preliminary MACT floor determination was from the dataset that specified control/abatement information or indicated no control. That is, all of those units on the database that did not specify control information were left out of this round of MACT floor determinations. This makes the data more conservative than if all the units were used.

- The requirements of Section 112 (d) of the 1990 CAA specify that for 30 sources or more in a category, MACT will be the average emission limitation achieved by the *best performing 12 percent* of existing sources in the category (*for which the administrator has emissions information)*. It was determined by the BWG for gas and oil fired systems the average of the "best performing 12 percent" would be the top 6 percent of the controlled systems. Anything below 6 percent would not be considered for the MACT floor.

- The units considered here burn only fossil fuels.

- The emissions database, state air regulations and permits information along with the RACT/BACT/LAER information would be reviewed to determine if there was enough information to determine a floor or to set potential HAP emission limits.

- The databases would be reviewed from a GCP and P2 perspective to determine if a MACT floor could be discerned from the data.

3.2 Available Data Information for the MACT Floor

3.2.1 ICCR Boiler Population Database

3.2.1.1 Gas Information. Version 3 of the EPA Boiler Database contained a total of 42,582 gas fired boilers. In the analysis of those boilers only 18,321 boilers had control or abatement information. The rest of the boilers did not specify any control information. There were only 177 boilers or about 0.97 % that indicated applicable add-on controls which would be considered to impact HAP emissions.

Because this was well below the 6 percent limit set by the BWG, it was determined that there was NO MACT FLOOR for Gas Fired Boilers.

Pollution Prevention (P2) and Good Combustion Practices (GCP) will be discussed below.

3.2.1.2 Distillate Oil Information. In Version 3 of the EPA Boiler Database there were 6604 boilers in the distillate (unheated) oil category. Of that, only 2623 boilers had control or abatement information or indicated that there were no controls. Seventy (70) boilers or 2.68% of the indicating boilers had controls of some sort.

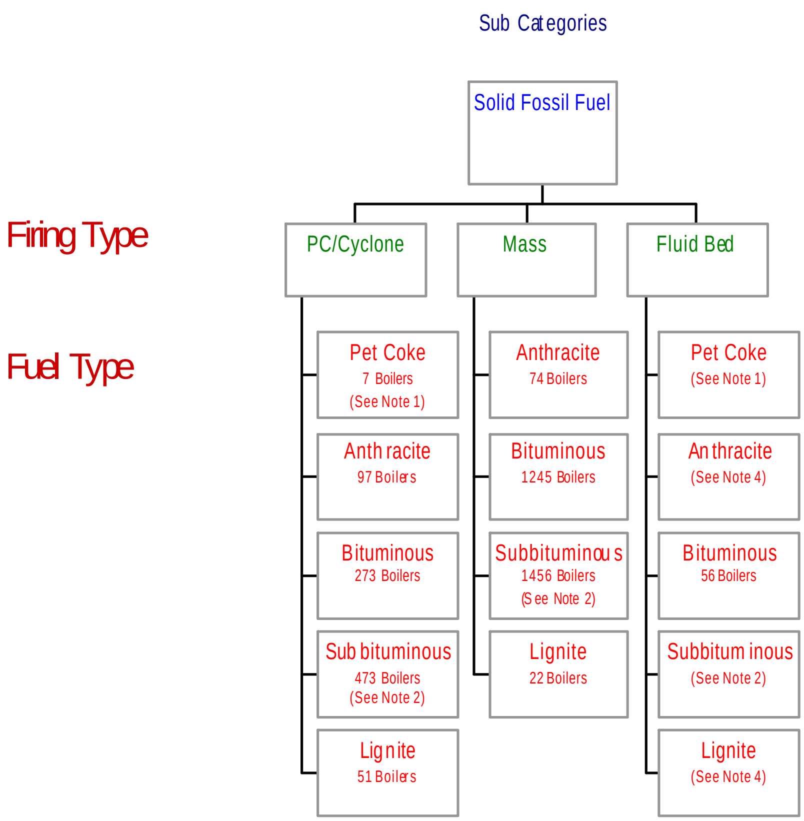
Because this was well below the 6 percent limit set by the BWG, it was determined that there was NO MACT FLOOR for Distillate Oil Fired Boilers. GCP and P2 will be discussed below.

3.2.1.3 Residual Oil. Version 3 of the EPA Boiler Database has 7945 boilers residual or heated oil boilers. Of those, 4810 boilers had control or abatement information. Only 264 boilers or 5.50 % had applicable add-on controls.

Again, because this level of add-on controls was less that the predetermined 6 percent cutoff, there is NO MACT FLOOR for Residual Oil Fired Boilers. GCP and P2 will be discussed below.

3.2.1.4 Coal.

Figure 1: Coal Fired Subcategories



Note 1 34 Petroleum Coke Boilers were identified in the Inventory Database with no boiler type

Note 2 33 Subbituminous Boilers were identified in the Inventory Database with no boiler type

Note 3 404 Boilers were identified in the Inventory Database with no boiler type or fuel type

Note 4 No Boilers were identified in the Inventory Database for these types; These could exist

5

At this time, no determinations have been made for the MACT floor for any of the boiler types listed above.

3.2.2 ICCR Boiler Emissions Database

The Boiler Work Group reviewed the ICCR Emissions Database to determine if the emissions data from gas- and oil-fired boilers could be used for MACT floor. Based on a review of the available emissions information, the Boiler Work Group determined that the existing emissions data are inadequate to identify a best performing group of existing boilers and to identify achievable emission limitations for existing boilers.

3.2.2.1 Gas Boiler Emissions Database Information. The ICCR Emissions Database for boilers fired with gas includes over 20 air emission test reports for HAPs. Gas-fired boilers in the database range in size from 2 MMBtu/hr to 7,500 MMBtu/hr heat input, or from less than 1 MW to 750 MW. The test reports represent tests conducted on 50+ boilers (as compared to over 40,000 gas-fired boilers in the ICCR Inventory Database). The database includes data from few boilers in the industrial sector (e.g., oil and refining), but mostly from very large boilers in the utility sector. A large majority of the source tests were conducted in the State of California as part of the AB2588 (Air Toxics "Hot Spots" Information Assessment Act of 1987) program.

The HAP emissions information in the ICCR Emissions Database for gas-fired boilers is very limited. In addition, nearly all of the emissions information is from very large boilers in the utility industry. The Boiler Work Group determined that this information may not be representative of emissions of gas-fired boilers that are in the commercial/institutional/industrial boilers source category due to differences in design, control equipment, and operational practices.

The Boiler Work Group noted the deficiencies in the ICCR Emissions Database for possible MACT control techniques. There is no data to evaluate control efficiencies.

The Boiler Work Group also noted that the HAP emission levels for gas-fired boilers reported in the ICCR Emissions Database are variable. For example, formaldehyde and benzene levels for gas-fired boilers cover two-to-three orders of magnitude. This is consistent with the recent American Petroleum Institute study titled "Emissions Variability on Boilers"(Appendix 2) that discusses this variability. The study states that, "The variability in the ICCR emissions database arises from the inherent variability in the combustion and measurement processes. This variability is magnified in the field due to differences in sampling and analytical methods, to differences in design, operational parameters, and location, as well as the level of data quality assurance screening."

3.2.2.2 Conclusions from Oil Emissions Database Information. The Boiler Work Group reviewed the ICCR Emissions Database for oil fired boilers to determine if the emissions data could be used for the MACT floor determination. Based on a review of this information, the Work Group determined that the existing emissions data are inadequate to identify a best performing group of existing boilers and to identify achievable emission limitations for existing boilers. The actual test reports were not completely reviewed, but analysis of the emissions database provides the following insights:

Many “Fuel Oil” fuel type units, which are generally interpreted as distillate oil fired units, are fired with residual oil as indicated by the fuel data information.

Some of the boilers are identified as being originally designed for coal firing and tested while firing oil. This leads to incorrect interpretation of controls which are applied to oil fired boilers.

In some cases, it is noted that where particulate collection devices are installed, they were not in operation during the emission tests. Other tests did not indicate whether this was the case or not.

Most of the emissions test data is from electric utility units and not from industrial boilers. While HAP emissions from utility units could be similar to industrial units, that is not an indication of what equipment is installed on industrial boilers.

Much critical data is not listed in the database or indicated as “Not Provided.”

There are orders of magnitude differences in HAP emission rates from different runs and tests on the same unit with no other apparent differences in operation or other data to indicate a cause for the variation. This leads to a conclusion of inherent variability in HAP emission rates and an inability to establish an emission rate suitable for MACT floor determination.

Many HAP emissions are truly a function of the fuel properties. No fuel data is provided.

There is conflicting information in the database with no explanation, e.g., “No Equipment” vs the comment information.

Some test data is from a very small boiler with uncharacteristically high excess air levels and is not indicative of typical industrial boilers.

There is no consistency of data and an inadequate number of data points upon which to establish a MACT floor.

3.2.2.3 Conclusions from Coal Emissions Database Information. Version 3 of the Emissions Database contains information from 255 sites or conditions for coal fired units. Some sites were tested under different conditions, like before and after air pollution control devices. The 255 tests resulted in 6550 stack tests for individual parameters. In other words, about 25 parameters were identified per site / condition.

The database is mostly from the work done in the report to Congress entitled “Study of Hazardous Air Pollutant Emissions from Electric Steam Generating Units - Final Report to Congress”. This study was done for larger utility sources but the data should be comparable to ICCR coal sources. Other database sources were from AP42 information and from STIRS.

The database is difficult to interpret due to the number of abatement device combinations. In order for the database to be used for rulemaking the subcategories must be defined and then the database be sorted by the subcategories and then by the abatement devices. These steps will be tedious since much of the information in the database fields do not provide enough information to easily sort items such as abatement equipment.

3.2.3 State Air Regulations and Air Permit Limits for HAPs

For the purpose of MACT floor, the Boiler Work Group limited its review of State air regulations and air permit limits to HAPs only. Although some States regulate air emissions of volatile organic compounds (VOCs) from existing boilers, and some HAPs are VOCs, the control of VOCs does not necessarily indicate control of HAPs. Similarly, although some States regulate air emissions of particulate matter (PM) from existing oil-fired boilers, and some HAPs are PM, the control of PM does not necessarily indicate control of HAPs. Therefore, the Boiler Work Group concluded that VOC and PM emission limitations are insufficient, at this time, to be used as the basis for HAP emission limitations for gas and oil-fired boilers.

Available information on state air regulations and air permit limits for HAPs was obtained from The following sources:

State regulations obtained by members of the Boiler Work Group RACT/BACT/LAER Databases, and permit limit information in the ICCR Population Database for Boilers.

The Work Group's findings on state air regulations for HAPs are presented in **Section 3.2.3.1** of this report. The findings on air permit limitations for HAPs are presented in **Section 3.2.3.3** of this report.

3.2.3.1 State Regulations. Members of the Boiler Work Group contacted State, local, and regional air pollution control agencies and obtained copies of their regulations for boilers. Members also developed a survey form that was sent to agencies that requested specific information on emission limits and controls. The results of the survey responses and the information in the regulations were summarized into several tables for use in this analysis.

Based on a review of information obtained by members of the Work Group, the Boiler Work Group was unable to identify any state air emission regulations that establish specific emission limitations for HAP emissions from natural gas-fired or fuel oil-fired boilers. Time did not allow a sufficient review of coal fired boilers.

3.2.3.2 RACT/BACT/LAER Databases. The RACT/BACT/LAER Clearinghouse contains information from air permits submitted by most of the state and local air pollution control programs in the United States. The database is available on-line at the TTN web site of the EPA: http://www.epa.gov/ttn/catc in the CATC (Clean Air Technology) technical site

Emissions limits for boilers were searched by downloading all available databases (historical, transient, and current) of the RACT/BACT/LAER Clearinghouse. The historical, transient, and current RACT/BACT/LAER databases were searched individually for state air permit limitations for boilers. Information was obtained on 15 fuel oil fired boilers out of 14,510 total in the inventory database. HAP permit limits were reported for at least one of the following pollutants: Arsenic, Beryllium, Bromine, Cadmium, Chromium, Copper, Formaldehyde, Lead, Manganese, Mercury, Nickel, Polycyclic Organic Materials (POMs), Selenium, and Vanadium. No HAP permit limits were identified for natural gas-fired boilers.

3.2.3.3 Permit Limit Information. Version 3 of the ICCR Population Database includes HAPs air permit limits for 17 gas-fired boilers, out of 42,582 total gas-fired boilers, and no fuel oil-fired boilers out of 14,510 total fuel oil-fired boilers. HAP permit limits are reported for at least one of the following pollutants: Benzene, Chlorine, Ethylbenzene, Formaldehyde, Hydrogen chloride, Toluene, and Vinyl chloride.

Permit limits were identified for boilers in both the RACT/BACT/LAER database and the inventory database. The Boiler Work Group determined that these permit limits should not be used as the basis for MACT floor since:

1. There was insufficient information in the ICCR Population Database to allow the Boiler Work Group to properly subcategorize the units.
2. It is unclear whether the permit limitations are based on emissions testing or on the use of emission factors, such as AP-42.
3. The 15 fuel oil-fired boilers and 17 natural gas-fired boilers represent less than 0.2 percent of fuel oil-fired boilers and less than 0.05 percent of the natural gas-fired boilers in the ICCR inventory database.

3.3 Emission Control Techniques

Good Combustion Practices (GCP) which could potentially impact organic HAP emissions are discussed under the Good Combustion Practices section.

The Boiler Work Group assessed possible emissions control techniques which could impact HAP emissions from gas and oil fired boilers.

3.3.1 Gas Fired Boilers

The inventory database indicates a low percentage of gaseous fired boilers being equipped with controls which could reduce mercury, inorganic HAP, and metal emissions. However, that data has not been verified at this time, and it is believed that those indicated units are designed for some fuel other than natural gas. There is no knowledge within the Work Group of situations where add-on controls are used on gas fired boilers. Based on the data reviewed, the Boiler Work Group concluded that no MACT Floor could be established on the basis of emissions control techniques.

3.3.2 Distillate (Unheated) Oil Fired Boilers

The inventory database for distillate oil fired boilers was reviewed by ERG and determined that there are very few add-on controls which could reduce mercury, inorganic HAP, and metal emissions for distillate oil fired boilers. It is believed that some, if not all of those indicated boiler controls are associated with another fuel rather than distillate oil. (For example, 0.46% of units with ESP's, 0.69% with cyclones, 0.04% with gas absorbers, 0.04% with activated carbon adsorption). Based on the data reviewed, the Boiler Work Group concluded that no MACT Floor could be established on the basis of emissions control techniques.

3.3.3 Heated (residual) Oil Fired Boilers

The inventory database indicates a low percentage of residual oil fired boilers being equipped with controls which could reduce mercury, inorganic HAP, and metal emissions. However, that data has not been verified at this time, and it is believed that many of those indicated units are designed for some fuel other than residual oil. There are some residual oil fired boilers which have SO2 scrubbers installed, and those do provide some HAP emission reductions. However, they are a small percentage of total (0.69%) prior to verification of the database. Based on the data reviewed, the Boiler Work Group concluded that no MACT Floor could be established on the basis of emissions control techniques.

3.4 Good Combustion Practices for Oil and Gas Fired Boilers

The Boiler Work Group assessed good combustion practices for gas and oil fired boilers by (1) researching and reviewing possible good combustion practices for the purpose of HAP reduction from boilers and (2) assessing the prevalence of those practices by reviewing information available in the ICCR Population database, information from state air permitting authorities, and the expertise of Work Group members.

Based on the information review thus far and the discussion below, the Boiler Work Group has tentatively concluded that no good combustion practices should be included in the MACT Floor for existing gas or oil fired boilers.

Possible Good Combustion Practices Include:

3.4.1 Gas Fired Boilers

3.4.1.1 Fuel/air ratio control. For use by the Economics subgroup, several possible GCP practices were identified for gaseous fuels. Those included practices, which controlled fuel/air ratio by various methods and were assumed to provide possible minor reductions in organic HAPs. Some gas fuel fired boilers were identified to have GCP in the Inventory Database, but only a very low number (0.43%). There was no data in the emissions database, which could be used to quantify any HAP emissions reduction associated with those practices. The PERF test report found no significant difference in HAP emissions with any additional fuel/air controls over those routinely employed by boilers. All existing boilers must use fuel/air ratio controls of some sort to comply with existing safety and air permit requirements. Based on the information review thus far and the above discussion, the Boiler Work Group has tentatively concluded that establishing GCP based on fuel/air ratio control as part of the MACT Floor is not recommended. However, there were some differing opinions on the ability of fuel to air ratio to help control HAP emissions (see Sect. 3.6).

3.4.1.2 Maintenance practices. Poor maintenance practices of boilers could possibly lead to deterioration of unit efficiency and incomplete fuel combustion, which could lead to, increased HAP emissions. However, existing economic drivers and existing permit requirements force attention to proper maintenance. Maintenance practices can also vary significantly depending on the design and operating characteristics of individual boilers. There is also no data available in the inventory or emissions database upon which to base any quantification of HAP emissions impact based on levels of maintenance. Since maintenance practices are highly variable, it is not practical to quantify the impact of maintenance practices on HAP emissions. Based on the information review thus far and the above discussion, the Boiler Work Group has tentatively concluded that establishing GCP based on maintenance practices as part of the MACT Floor is not recommended. However, some in the BWG were of the opinion that Maintenance Practices may help curb HAP emissions (see Sect. 3.6).

3.4.1.3 State Regulations. EPA has recently summarized data from state regulations relative to practices that could be considered GCP. These summary tables indicate on a gross basis the number of boilers that may be required to implement the practices. However, it is recognized that the number of units is inflated over the actual number due to an inability to differentiate the actual number of boilers in the inventory database which are required to meet those requirements, since they are directed at specific locations, heat input capacities, and other limiting criteria. Thus, the number of boilers impacted is likely to be much lower than indicated in the tables. Conversely, there may be additional local requirements which may not be captured in the present tabulations. Additional efforts would be needed to enable any conclusions from that data.

However, some observations could be obtained from the state data. First, the boilers subject to these practices are doing so as part of ozone nonattainment programs targeting NOx emission reductions, not HAP emission requirements. Second, there are boiler size applicability limits to many of the practice requirements, and that would greatly influence the number of units impacted. There is also no information relative to the HAP emission impact of any of the practices. Based on the information review thus far and the above discussion, the Boiler Work Group has tentatively concluded that establishing GCP based on state regulations as part of the MACT Floor is not recommended. Additionally, there were some in the BWG that thought that not all the state regulations had been reviewed adequately to determine if they set rules that might control HAP emissions (see Sect. 3.6).

3.4.2 Oil Fired Boilers

3.4.2.1 Fuel/air ratio control. For use by the Economics subgroup, several possible GCP practices were identified for liquid fuels. Those included practices that controlled fuel/air ratio by various methods and were assumed to provide possible minor reductions in organic HAPs. Some oil fired boilers were identified to have GCP in the Inventory Database, but only a very low number (0.99% for distillate oil or 0.34% for residual oil). There was no data in the emissions database that could be used to quantify any HAP emissions reduction associated with those practices. All existing boilers must use fuel/air ratio controls of some sort to comply with existing safety and air permit requirements. Based on the information review thus far and the above discussion, the Boiler Work Group has tentatively concluded that establishing GCP based on fuel/air ratio control as part of the MACT Floor is not recommended. See Section 3.6 for differing opinions by some BWG members.

3.4.2.2 Maintenance practices. Poor maintenance practices of boilers could possibly lead to deterioration of unit efficiency and incomplete fuel combustion that could lead to increased HAP emissions. However, existing economic drivers and existing permit requirements force attention to proper maintenance. Maintenance practices can also vary significantly depending on the design and operating characteristics of individual boilers. There is also no data available in the inventory or emissions database upon which to base any quantification of HAP emissions impact based on levels of maintenance. Since maintenance practices are highly variable, it is not practical to quantify the impact of maintenance practices on HAP emissions. Based on the information review thus far and the above discussion, the Boiler Work Group has tentatively concluded that establishing GCP based on maintenance practices as part of the MACT Floor is not recommended. See Section 3.6 for other opinions regarding maintenance practices and HAP emissions control.

3.4.2.3 State Regulations. EPA has recently summarized data from state regulations relative to practices that could be considered GCP. These summary tables indicate on a gross basis the number of boilers which may be required to implement the practices. However, it is recognized that the number of units is inflated over the actual number due to an inability to differentiate the actual number of boilers in the inventory database which are required to meet those requirements, since they are directed at specific locations, heat input capacities, and other limiting criteria. Thus, the number of boilers impacted is likely to be much lower than indicated in the tables. Conversely, there may be additional local requirements that may not be captured in the present tabulations. Additional efforts would be needed to enable any conclusions from that data.

However, some observations could be obtained from the state data. First, the boilers subject to these practices are doing so as part of ozone nonattainment programs targeting NOx emission reductions, not HAP emission requirements. Second, there are boiler size applicability limits to many of the practice requirements, and that would greatly influence the number of units impacted. There is also no information relative to the HAP emission impact of any of the practices. Based on the information review thus far and the above discussion, the Boiler Work Group has tentatively concluded that establishing GCP based on state regulations as part of the MACT Floor is not recommended. See Section 3.6 regarding the opinions of some BWG members that HAP emissions may be coincidentally controlled by some state imposed rules.

3.5 Pollution Prevention (P2)

3.5.1 Boiler Efficiency Considerations

As noted above, boiler efficiency could be related to HAP emissions on the basis of increased fuel input requirements in order to meet output demands. However, it is extremely difficult to establish a MACT Floor which could include consideration of efficiency in any way except as a compliance alternative to a MACT numerical standard as discussed in the P2 subgroup documents. The inherent efficiency of every boiler is unique, and the ability to influence that efficiency is limited by many technical, economic, and operational considerations. The inherent boiler efficiency varies as a function of boiler load and many other conditions. Therefore, while this could be further considered, based on available information and the expertise of the Boiler Work Group, it is not recommended to include boiler efficiency provisions as part of the MACT Floor. See Section 3.6 below for an alternative opinion regarding HAP control and boiler efficiency.

3.6 Other GCP/P2 Considerations

Consensus was not reached in the BWG regarding NO MACT FLOOR based on GCP or P2. It was perceived by some in the BWG that perhaps there were some GCP or P2 practices that coincidentally controlled HAPs. There was no time to investigate this although several technical experts disagreed because there was no data to support such an argument. There were also some arguments regarding good operating efficiencies reducing the amount of fuel needing to be burned and thus reducing HAPs.

4.0 HAP EMISSION LIMIT CONSIDERATIONS

4.1 Emissions from ICCR Emissions Database

As stated above in Section 3.2.2, ICCR Boiler Emissions Database, there were no discernible specific limits identified for HAPs emissions in the review of the ICCR Emissions Database. Therefore, there are no recommendations for HAP emission limits.

4.2 State Air Emission Regulations for HAPs

As stated above in Section 3.2.3, State Air Regulations and Air Permit Limits Databases, there were no discernible specific limits identified for HAPs emissions from the review of thestate air regulations. Therefore, there are no recommendations for HAP emission limits.

4.3 Air Permit Limitations for HAPs

As stated above in Section 3.2.3, State Air Regulations and Air Permit Limits Databases, there were no discernible specific limits identified for HAPs emissions from the review of the air permits. Therefore, there are no recommendations for HAP emission limits.

5.0 CONCLUSIONS:

The BWG has set the following subcategories for fossil fuels:

- Natural Gas - which includes wellhead gas, pipeline gas, liquified petroleum gas (LPG).
- Distillate Oil
- Residual Oil
- Coal with the additional subcategories by fuel type of anthracite, lignite, bituminous petroleum coke and sub bituminous. Within these fuel types are the following types of boiler design: pulverized coal/cyclone, mass fired, fluidized bed.

It should be noted that although arguments are presented in this document for including gaseous fuels derived from processing of crude oil, petroleum or petrochemicals in the definition of natural gas, consensus was never reached on the issue.

Once the subcategories were established the various databases were reviewed to determine the MACT floor and to help set HAP emission limits for natural gas, distillate oil and residual oil. Time expired on the ICCR FACA process and a review for coal was not completed.

After a review of the inventory database, the emission database, the state regulation and permit databases and the RACT/BACT/LAER databases there was no data that indicated a MACT Control requirement or a clear HAP emission limit.

The review of Good Combustion Practices did not indicate specific GCP requirements that a MACT floor could be established on. However, there was concern by some members of the BWG that further investigation may indicate that some GCP, not initially defined as HAP controls may coincidentally be abating HAPs.

Therefore, with all of the above reviews that were performed and based on the subcategorization and assumptions that were made, there was a conclusion NO MACT Floor can be identified at this time for oil and gas. Coal will have to be further studied to determine its MACT Floor. It was further concluded that there are no HAP emission limits associated with this MACT Floor.

It is now recommended that the Coordinating Committee of the ICCR FACA forward these determinations and associated rationale to the EPA.

APPENDIX 1

Boilers Working Group - MACT Floor Documentation

Rationale for Broad Definition of Gaseous Fuels

Boilers Working Group - MACT Floor Documentation
Rationale for Broad Definition of Gaseous Fuels

Background

Emissions data on HAPs and criteria pollutants used in the MACT determination process originated from several sources, and have gone through several stages of screening and assessment, as described in the Boilers Working Group "HAPs of Interest Analysis". For gas-fired external combustion devices (i.e. Boilers and Process Heaters) three primary sources were utilized.

First, source test results collected under the California Air Toxics "Hot Spots" Inventory and Assessment Act (AB2588) have been compiled and quality reviewed in a joint effort by the Western States Petroleum Association (WSPA), the California Air Resources Board (CARB), and the American Petroleum Institute (API). The results of this investigation are compiled in the 3-volume Draft Report titled "Development of Toxics Emission Factors for Petroleum Industrial Combustion Sources" (D. W. Hansell and G. C. England, EER Corporation, September 1997). It was provided to the US EPA in October 1997, and is available in the ICCR docket. A presentation on this database was provided to a joint meeting of all the ICCR Work Group members on November 18, 1997. The validation and verification processes used to quality assure these data makes this the most reliable and comprehensive compilation of field emission source test data for petroleum industry combustion sources. The final report is currently being printed by API (August 1998) and will be available to the Coordinating Committee and the US EPA by mid-September.

The second source of emissions test data came from the Petroleum Environmental Research Forum (PERF) 92-19 "Toxic Combustion Byproducts" project. In 1992 PERF initiated a Cooperative Research and Development Agreement (CRADA) with the U.S. Department of Energy, and with EPA participation, performed an experimental and fundamental investigation of chemical and physical mechanisms governing organic HAP formation, destruction, and emissions. These tests on full-scale burners were performed at the Sandia National Laboratories/Livermore. This program produced data of very high quality that shed light on many of the key questions surrounding the field data. The results of this project were presented to the Coordinating Committee on July 22, 1997, and are summarized in a paper titled "Organic Hazardous Air Pollutant Emissions from Gas-Fired Boilers and Process Heaters" (G.C. England and D.W.Hansell, EER Corporation, July 1997) which is available in the ICCR docket. The PERF 92-19 CRADA Final Report, "The Origin and Fate of Toxic Combustion Byproducts in Refinery Heaters: Research to Enable Efficient Compliance with the Clean Air Act" (August 5, 1997), and be accessed at http://www.epa.gov/ttn/iccr/dirss/perfrept.pdf. The complete 10-volume study including test reports and appendices has been placed in the ICCR docket.

Lastly, the ICCR Emissions Database, V.2, provides a compilation of emissions test data made available from existing electronic databases such as STIRS, and other information from state and local agencies. Emissions information collected from the 114 ICR survey was also added to this database.

Conclusions

Based on the discussion above and the references cited therein, we conclude that:

HAP emissions from all gas-fired sources are generally very low, but exhibit inherent variability associated with process fluctuations and sampling and analysis uncertainties.

The PERF data referenced above demonstrate that HAP emissions from typical industry gas fired burners, under a variety of operating conditions are all very low, at or near the detection limits of the best measurement methods. In addition, field source test data, such as the WSPA/API database indicate that annual total HAP emissions from operating gas-fired heaters and boilers are well below the major source definition.

HAP emissions from devices fired by either natural gas or petroleum processing derived gas are similar, on a Btu basis.

The controlled laboratory testing (PERF study) and the WSPA/API field test data demonstrate that emissions factors derived independently for different gaseous fuels are indistinguishable, when measurement uncertainty and process variability are taken into account (Figures 1). The emission factor derivation process accounts for the different heat content of the variety of the gases used in practice, and which like natural gas, consist primarily of hydrocarbons mixtures.

HAP emissions from gas-fired boilers and process heaters are equivalent.

Design practices are such that the same burner types are used for constructing both gas-fired process heaters and boilers. In addition, the field emissions data for boilers and process heaters, fired by a variety of gaseous and liquid fuels, was shown to be similar (Figure 2). The data demonstrate that emissions from boilers or process heaters vary by size (heat input) but are otherwise expected to be equivalent.

Recommendations

For the purposes of subcategorizing boilers – it is recommended that a single subcategory be established for devices firing the following gaseous fuels:

Natural Gas/Wellhead Gas: a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane;

Liquid Petroleum Gas: as defined by the American Society of Testing and Materials in ASTM D1835-82, Standard Specification for Liquid Petroleum gases.

Petroleum Derived Gas: Gaseous fuel derived from the processing of crude oil, petroleum, or petrochemicals.

Since consistent definitions of the fuels combusted are desirable for all ICCR sources, we recommend that the Coordinating Committee adopt the three-part definition above which is consistent with that adopted by both the Process Heaters and Turbines Working Groups for their gaseous fired devices.

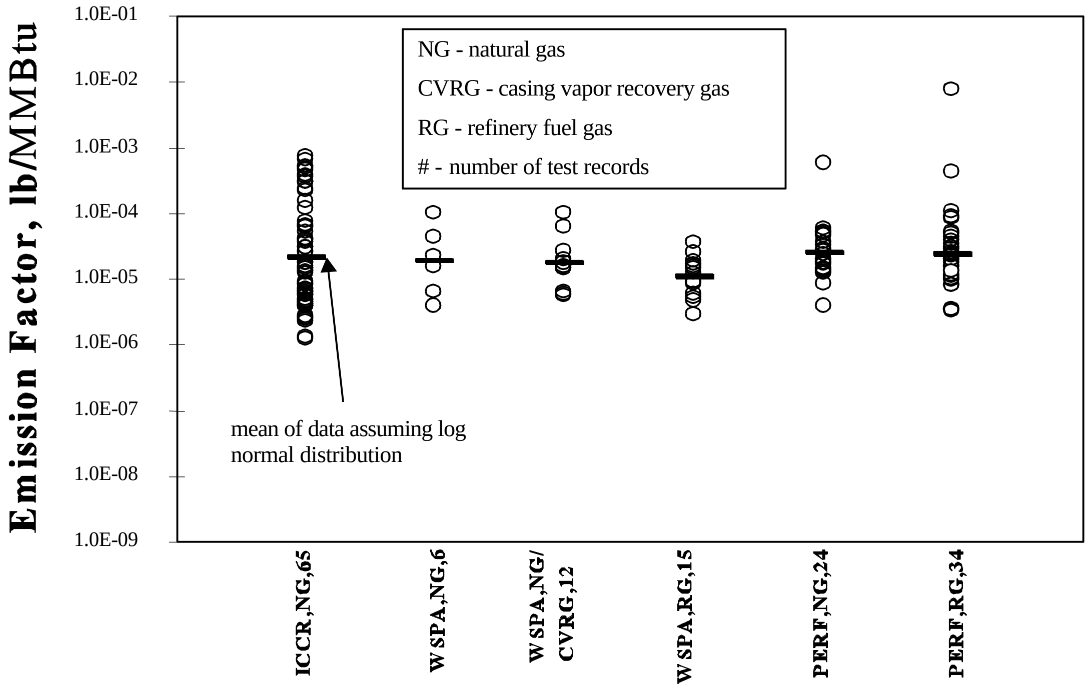
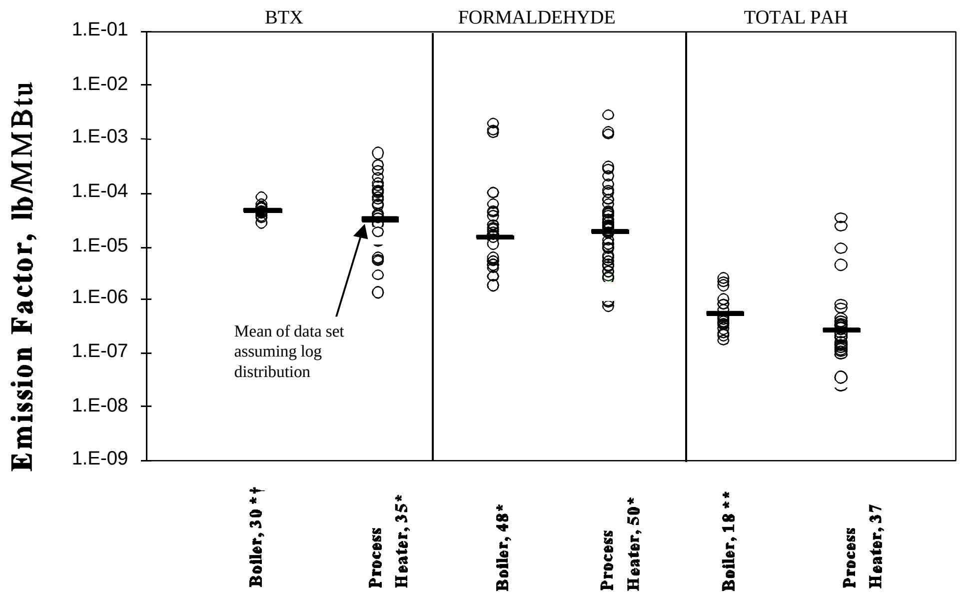


Figure 1. Formaldehyde emissions as a function of fuel type for gas fuel fired boilers (ICCR, WSPA, and PERF data).



* Includes crude, FO #6, and gaseous fuel (primarily gas)

** Includes FO #6 and gaseous fuel (primarily gas)

† Number following label = number of test records

Figure 2. Comparison of HAP emissions data for Boilers and Process Heaters (WSPA data).

APPENDIX 2

Emissions Varability On Boilers

Emissions Variability for Boilers

Conclusion: Considerable variability is observed in the reported emissions of HAPs from similar sources firing similar fuels under similar operating conditions. This level of variability is not uncommon in databases of this type and is to be expected when searching for trace emissions at the limits of detection. The variability in the ICCR emissions database arises from the inherent variability in the combustion and measurement processes. This variability is magnified in the field due to differences in sampling and analytical methods, to differences in design, operational parameters, and location, as well as the level of data quality assurance screening.

When analyzing the boiler emissions information in the ICCR database, one observes that there is considerable variability in the reported emissions of hazardous air pollutants from similar sources firing similar fuels under similar operating conditions. When looking at any process, there is a natural variability that is inherent to both the process and the device used to measure the process. The vast majority of this variability is most likely due to sampling and analytical errors. Some small portion of the variability may be due to minor differences in the design, operation, and geographic location of the combustion devices.

An instructive demonstration of this inherent variability can be found in the PERF 92-19 study. As shown in Figure 2-1, variability of up to two orders of magnitude can exist even in situations where the combustion device, the measurement techniques, and the operating parameters are highly standardized. This exceedingly high quality data illustrates what might be called the "irreducible minimum" or "inherent" variability that is unavoidable when searching for trace HAP emissions at the limit of detection of the most sophisticated of sampling and analytical methods.

The PERF HAPs emission data were collected at the Sandia National Laboratory, Livermore, California, Combustion Research Facility's Burner Engineering Research Laboratory (BERL), a 2.0 MMBtu/hr test facility for full-scale industrial burners. Before and after each of the five different full-scale commercial burner test sequences, "Regulatory Base Case" repetitions were carried out to make sure that nothing in the physical setup had changed in the interim between sequences nor over the period of days required to complete a given test sequence. While this was done primarily to make sure that "the same" system was being tested each time, this procedure of Regulatory Base Case repetition provides the concomitant benefit of demonstrating the irreducible minimum data variability for trace HAPs.

The PERF "Regulatory Base Cases" characterized normal operation at 2 MMBtu/hr at a stoichiometric ratio of 1.25 (*i.e.*, 25% excess air) and furnace exit temperature 1600F firing either refinery fuel gas, the "A1" cases, or natural gas, the "A4" cases. The Regulatory Base Case "A1" fuel was a mixture of 16% hydrogen in natural gas plus propane to yield 1050 Btu/scf heating value while the Regulatory Base Case "A4" was pure natural gas with the same heating value of 1050 Btu/scf. Thus the Regulatory Base Case fuel mixtures, heating value, burner load, stoichiometric ratio and furnace exit temperature were all duplicated at each repetition as nearly as possible and in strict conformance with the highest EPA QA/QC protocols. The PERF 92-19

CRADA's Quality Assurance Project Plan, acknowledged by EPA as one of the best they have ever seen, guaranteed data of regulatory development quality.

As the sampling, analytical, and operating conditions at the BERL were more tightly controlled than would be possible in a field facility, the data from this study provides a benchmark for HAP emissions data variability. For example, one test team, on the same combustion device, using the same sampling and analytical methods conducted at the same laboratories collected all of the data. Yet even under these highly controlled conditions, substantial "inherent" HAP emissions data variability was observed.

This inherent variability that is observed even under the most controlled situations is magnified and added to in the field by many other sources of variability. These sources include differences in sampling and analytical procedures, detection limits, sample volumes, analytical accuracy and precision requirements, lab contamination, data reporting requirements, different sampling contractors, data reduction and data entry errors, etc. Many of these variables are listed in Table 2-1, which shows selected HAPs sampling and analytical procedures, detection limits, and acceptable analytical accuracy and precision requirements. As Table 2-1 illustrates, accuracy errors and imprecisions of up to 50% are allowed by many methods. These allowances will contribute to variability in measurements.

Another factor that impacts variability is the level of data quality assurance screening. The U.S. EPA has procedures for addressing low sensitivity, non-detect data and determining and eliminating outliers. For example, the WSPA/API/CARB database has undergone such a screening, which has to some extent lowered the overall variability. The ICCR Emissions Database has not undergone such a screening procedure.

To a much lesser extent, differences in boiler design, in the process operating conditions, and even in the location of combustion systems can contribute to the emissions data variability. For example, operational parameters such as swings in process feed rates and in load changes brought about by interactions with other processes could impact the variability. A combustion system located in a hot, humid climate may be operated differently than a system in a cold, dry climate. Differences can even be expected based upon changes in season i.e. between winter and summer.

Even if each of these many different aspects by themselves contribute only a small percentage of the overall variability, together they can add up to orders-of-magnitude differences in the measured emissions across the population of sources as observed in this MACT determination analysis. Lastly, it should be mentioned that a quantitative assessment of the relative contribution of the various factors discussed in the Section is not possible based on the information available in the ICCR databases.

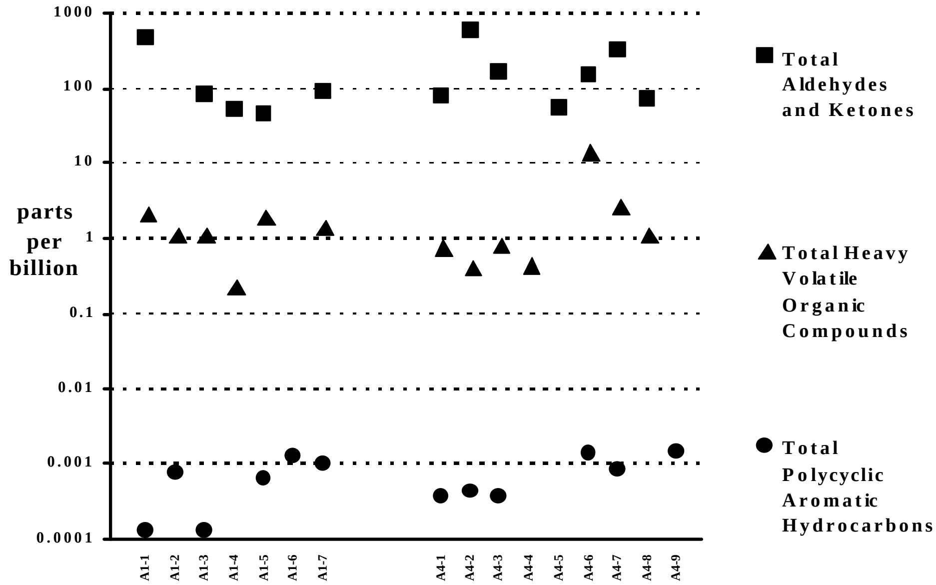


Figure 2-1. PERF 92-19 CRADA Regulatory Base Case Repetitions Illustrate Irreducible Minimum Variability when Searching for Trace Emissions at the Limit of Detection

TABLE 2-1. Selected HAPs Sampling and Analytical Procedures and Detection Limits

HAP	Sampling & Analytical Method(s)	Sampling Procedure	Analytical Procedure	Detection Limit (ng/dscm) (1)	Detection Limit (lb/MMBtu) (2)	Analytical Precision (%)	Analytical Accuracy (%)
PAH - Benzo(a)pyrene	CARB 429	Isokinetic with XAD-2 resin	HRGC/HR MS	5	2.7E-09	+/- 50	50-150
PAH - Benzo(a)pyrene	CARB 429	Isokinetic with XAD-2 resin	HRGC/LR MS	100	5.4E-08	+/- 50	50-150
PAH - Benzo(a)pyrene	EPA SW-846 M0010/ EPA SW-	Isokinetic with XAD-2 resin	LRGC/LR MS	1,000	5.4E-07	+/- 50	50-150
Formaldehyde		Hot wet extraction	FTIR	120,000	6.8E-05		
Formaldehyde	CARB 430	Non-isokinetic with DNPH	HPLC	10,000	5.4E-06	+/- 10	70-130
Formaldehyde	EPA SW-846 M0011/ EPA SW-	Isokinetic with DNPH	HPLC	800	4.4E-07		
Benzene	EPA SW-846 M0030/ EPA SW-	Non-isokinetic with Tenax	GC/MS	1,000	5.4E-07	+/- 50	50-150
Benzene	EPA Method 18	Non-isokinetic with Tedlar Bag	GC/PID/EC D	160,000	8.8E-05	+/- 5	90-110
Benzene	CARB 410A	Non-isokinetic with Tedlar Bag	GC/PID	11,000	5.8E-06	+/- 5	90-110
Benzene	CARB 410A	Non-isokinetic with Tedlar Bag	GC/FID/PI D	3,200	1.8E-06	+/- 5	90-110
Benzene	EPA SW-846 M0040/EPA TO-	Non-isokinetic with Tedlar Bag	GC/MS	1,600	8.8E-07	+/- 25	70-130
Benzene			FTIR	320,000	1.8E-04		
PCDD/PCDF-2,3,7,8-TCDD	EPA Method 23	Isokinetic with XAD-2 resin	HRGC/HR MS	0.005	2.7E-12		
PCDD/PCDF-2,3,7,8-TCDD	CARB 428	Isokinetic with XAD-2 resin	HRGC/HR MS	0.005	2.7E-12	+/- 30	60 - 140
PCDD/PCDF-2,3,7,8-TCDD	EPA SW-846 M0010/ EPA SW-	Isokinetic with XAD-2 resin	HRGC/HR MS	0.05	2.7E-11		
PCDD/PCDF-2,3,7,8-TCDD	EPA SW-846 M0010/ EPA SW-	Isokinetic with XAD-2 resin	HRGC/LR MS	50	2.7E-08		

In databases such as those used in the ICCR, the analytical procedure is the parameter that can be expected to have a large impact on the emissions variability. This is due to the fact that non-detect data are generally reported as either the full or one-half the detection limit. Thus, units with emissions below detectable levels will have very different reported emissions if they are tested by two methods with different detection limits.

For example, the detection limit for the polycyclic aromatic hydrocarbon benzo(a)pyrene is a factor of 200 lower if the sample is analyzed using high resolution gas chromatography (GC)/high resolution mass spectrometry (MS) rather than low resolution GC/low resolution MS. Therefore, if two similar sources are tested for benzo (a) pyrene, one using the high resolution technique and the other using the low resolution technique, and benzo (a) pyrene is not detected in either sample, the reported emissions will be 200 times higher for the source tested with the low resolution technique even if all other sources of variability are equivalent. Both techniques are valid, however the low-resolution technique is less expensive.

Attachment 7

Boiler Work Group Presentation on HAPs of Interest For Fossil Fuel-Fired Boilers

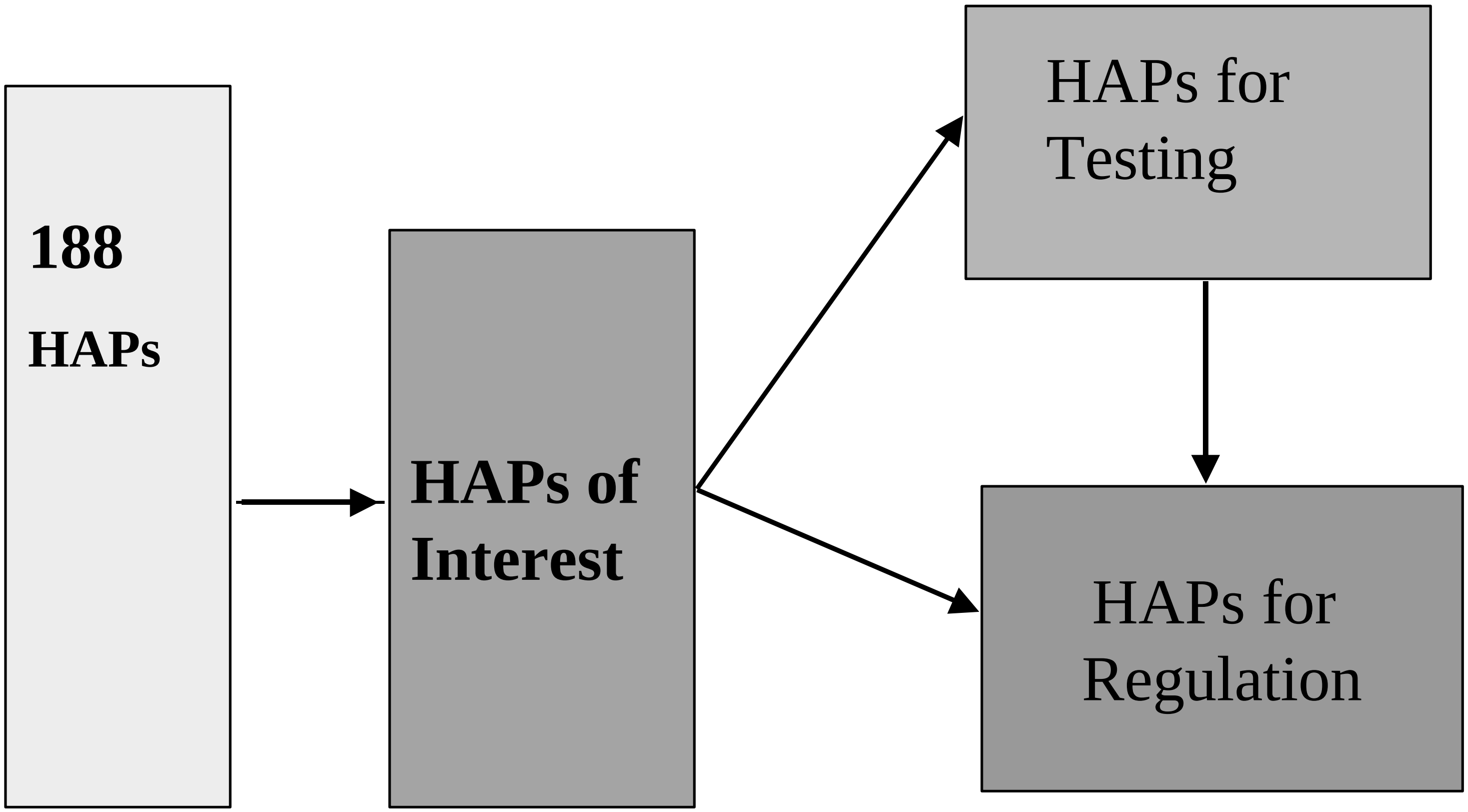
HAPs of Interest List
Boiler Work Group

Industrial Combustion Coordinated Rulemaking

Coordinating Committee

9/16/98

Definition of HAPs of Interest



Definitions - Gas/Oil/Coal

§ **GAS - Same as 40 CFR 60.41b**

- **Includes Wellhead, Pipeline, LPG Gases**
- **Gas Derived From Oil, Petroleum, Petrochemical Processing - Non Consensus to include with Gas**

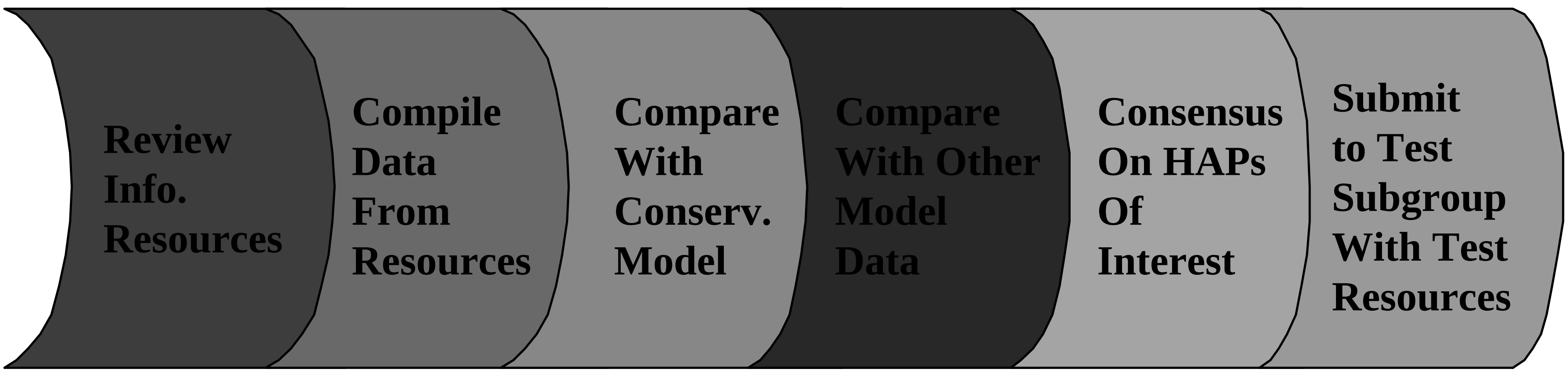
§ **OIL**

- **Distillate Oil - Same as 40 CFR 60.41b**
- **Residual Oil - Same as 40 CFR 60.41b**

§ **Coal**

- **Same as 40 CFR 60.41b. Includes Anthracite, Bituminous, SubBituminous, Lignite.**

Selection Process



Gas HAPs of Interest

Chemical	Chemical
Benzene	Phosphorus
Toluene	Dioxin
Hexane	Cadmium Compounds
POM's	Chromium Compounds
Formaldehyde	Cobalt Compounds
Nickel	Lead Compounds
Acetaldehyde	Manganese Compounds
Dibenzofurans	

Distillate Oil HAPs of Interest

Chemical	Chemical
Benzene	Arsenic
1,3 Butadiene	Beryllium
Dioxins/Furans	Cadmium
POMs/naphthalene	Chromium
Hydrochloric acid	Lead
Hydrogen fluoride	Manganese
Formaldehyde	Mercury
Acetaldehyde	Nickel

Residual Oil HAPs of Interest

Chemical	Chemical
Benzene	Arsenic
1,3 Butadiene	Beryllium
Dioxins/Furans	Cadmium
POMs/naphthalene	Chromium
Hydrochloric acid	Lead
	Phosphorus
Hydrogen fluoride	Manganese
Formaldehyde	Mercury
Selenium	Nickel

Coal HAPs of Interest

Chemical	Chemical
Benzene	Arsenic
Isophorone	Beryllium
Dioxins	Cadmium
POMs	Chromium
Hydrochloric acid	Lead
	Phosphorus
Hydrogen fluoride	Manganese
Acetaldehyde	Mercury
Acrolein	Nickel

Coal HAPs of Interest (Continued)

Chemical	Chemical
Phenol	Formaldehyde
Cobalt	Hexachlorobenzene
Selenium	Methyl Chloride
Cyanide	Methyl Iodide
Acrylamide	N-Nitrosodimethyl-amine
Acrylonitrile	1,1,2,2 Tetrachloroethane
2-chloro-acteophenone	Antimony Compounds
Ethylene Dibromide	Radionuclides

Attachment 8

Paper on HAPs of Interest for Fossil Fuel-Fired Boilers
(Closure Item)

Hazardous Air Pollutants (HAPS)

Of Interest for Fossil Fuel Fired Boilers

Boiler Work Group
Of The
Industrial Combustion Coordinated Rulemaking (ICCR)
Federal Advisory Committee

September 4, 1998

TABLE OF CONTENTS

<u>Section</u>

EXECUTIVE SUMMARY

This is the Boiler Work Group (BWG) report for the list of Hazardous Air Pollutants (HAPs) of Interest for fossil fired fuels (gas, distillate oil, residual oil and coal). It represents the consensus opinion of the Boiler Workgroup as determined in a meeting held in Ft. Collins, Colorado on April 30, 1998.

The BWG determined that the list of HAPs of Concern really be divided into three lists:

- HAPs OF INTEREST for further investigation
- HAPs that fall out on the HAPs of Interest List will then be looked at to see if they need to be tested. Those to be tested will become HAPs FOR FURTHER TESTING.
- HAPs FOR POTENTIAL REGULATION – These are HAPs that may need to be regulated or controlled.

A general protocol was developed to decide the final list of HAPs of Interest in each boiler fossil fuel group (natural gas, oils, and coal). The protocol included:

- Reviewing different reference sources to develop a list of HAPs of initial concern for each fuel category

- Compiling known emission rate data from reliable sources for those HAPs of initial concern,

- Determining the magnitude of HAPs emissions vented from boilers of 10 million BTU/hr (MMBTU/HR.), 100 MM BTU/HR., and 250 MM BTU/HR. firing rates.

- Comparing the actual emissions with deminimis limits derived from a very conservative stack model provided by the New Hampshire Dept. of Environmental Services (Air Resources Division).

- Performing a second screening of HAP of initial concern emission rates for a 250 MM BTU/Hr boiler. Actual emissions impact was determined using more realistic assumptions for the model boiler. The 250 MM BTU/Hr. boiler emissions were compared to the second round NHDES model levels, the Florida Ambient reference concentrations, and the BIF Levels (RAC).

- Developing the final list of HAPs of Interest for fossil fuel fired boilers based on:

    - HAPs that exceeded the models' screening levels
    - HAPs that were considered high toxic risks
    - HAPs that did not have enough data to support a recommendation

Below is the final List of HAPs of Interest. The HAPs that appear on this list may or may not appear on the list of HAPs for Testing or the list of HAPs for Regulation.

Table 1. Gas HAPs of Interest List

Chemical	Chemical
Benzene	Phosphorus
Toluene	Dioxin
Hexane	Cadmium Compounds
POM's	Chromium Compounds
Formaldehyde	Cobalt Compounds
Nickel	Lead Compounds
Acetaldehyde	Manganese compounds
Dibenzofurans	

Table 2. Distillate Oil HAPs of Interest List

Chemical	Chemical
Benzene	Arsenic
1,3 Butadiene	Beryllium
Dioxins/Furans	Cadmium
POM's/Naphthalene	Chromium
Hydrochloric Acid	Lead
Hydrogen Fluoride	Manganese
Formaldehyde	Mercury
Acetaldehyde	Nickel

Table 3. Residual Oil HAPs of Interest List

Chemical	Chemical
Benzene	Arsenic
1,3 Butadiene	Beryllium
Dioxins/Furans	Cadmium
POM's/Naphthalene	Chromium
Hydrochloric Acid	Lead
Hydrogen Fluoride	Manganese
Formaldehyde	Mercury
Selenium	Nickel
	Phosphorus

Table 4. Coal HAPs of Interest List

Chemical	Chemical
Benzene	
Isophorone	Nickel
Dioxins	Phenol
POMs	Selenium
Hydrochloric Acid	Cyanide
Hydrogen Fluoride	Acrylamide
Acetaldehyde	Acrylonitrile
Acrolein	2-chloro-acetophone
Methyl Iodide	Ethylene Dibromide
Arsenic	Formaldehyde
Beryllium	Hexachlorobenzene
Cadmium	Methyl Chloride
Chromium	N-Nitrosodimethylamine
Lead	1,1,2,2 Tetrachloroethane
Phosphorus	Antimony Compounds
Manganese	Radionuclides
Mercury	Cobalt

II INTRODUCTION

The Boiler Work Group (BWG) of the Industrial Combustion Coordinated Rulemaking (ICCR) FACA process undertook the task of determining which Hazardous Air Pollutants (HAPs) of Interest should be listed for further study. The BWG further subdivided its group in to three Subgroups: Fossil fired systems (oil, gas, and coal), clean wood fired systems, and non-fossil fired systems that included all the remaining boilers. This report will address the HAPs of Interest for fossil fired boilers (gas, oils and coal).

Major contributors to this consensus report are from the ad hoc HAPs Subgroup members listed below:

NAME	REPRESENTING	ISSUE
Andrew Bodnarik	New Hampshire DES Air Resources	HAPs Review
Wendell Brough	Celanese	Natural Gas
Mark Bryson	Alcoa	Coal
Alex Johnson	Citizens Commission for Clean Air In the Lake Michigan Basin	Coal
Gunseli Shareef	Radian	Oil

The items included in this report reflect a consensus agreement among BWG members. Any dissenting comments will be so noted.

III. DEFINITIONS

The following topics were defined as a necessity to reach the final list of HAPs of Interest:

A. HAPs

1. HAPs of Interest

The HAPs list will be broken down into three distinct categories: HAPs of Interest, HAPs for Testing and HAPs for Regulation. The HAPs of interest included those chemicals that needed to be further investigated because they fell into one or more of the categories below:

- above initial screening levels and/or,
- potential of extreme toxicity

- listed as an urban air toxic
- HAPs having little or no emission data.

2. HAPs for Further Testing

HAPs that appear on the HAPs of Interest List will then be reviewed to see if they need to be tested. Those that don't have adequate emission data should be further tested. This list will become HAPs FOR FURTHER TESTING.

3. HAPs for Potential Regulation

These are HAPs of Interest that may need to be regulated or controlled. This list of HAPs of Potential Regulation may be longer or shorter than the list of HAPs of Interest or HAPs for Further Testing.

B. Natural Gas

The definition for Natural Gas was taken from the NSPS Rules in 40 CFR 60.41 b: a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or (2) liquid petroleum gas, as defined by the American Society for Testing and Materials in ASTM D1835-82, "Standard Specification for Liquid Petroleum Gases".

For all practical purposes, this included wellhead gas (gas straight from the ground). Mercury in wellhead gas was initially a concern of the Boiler Work Group. However, a paper is provided as Appendix 1 discussing why Mercury should not be an issue.

Liquid Petroleum Gas (LPG): LPG is propane and/or butane often with small amounts of propylene and butylene sold as a pressurized liquid. LPG is included in this definition of Natural Gas.

Gaseous Fuels Derived from processing of crude oil, petroleum or petrochemicals: There was not a consensus in the Boiler Work Group to include this in the definition of Natural Gas. The Petroleum Environmental Research Forum Project 92-19 (PERF Data) found no significant difference in air toxic emissions between burning natural gas, as defined above, and these process derived gaseous fuels. Enclosed in Appendix 2, there is a paper entitled "Rationale for Broad Definition of Gaseous Fuels" which supports the argument of incorporating gaseous fuels derived from processing of crude oil, petroleum or petrochemicals into the definition of Natural Gas.

However, at this time, because of not being able to review and digest the information, the BWG did not come to consensus on this definition and is deferring to the EPA the decision of the incorporation of these process derived fuel types with Natural Gas.

C. Oils

- Distillate Oil (also called unheated oil): Fuel oils that comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Material in ASTM D396-78, Standard Specifications for Fuel Oil. (40 CFR 60.41 b)

- Residual Oil (also called heated oil): Crude oil, and all fuel oil numbers 4,5, and 6 as defined by the American Society of Testing and Materials in ASTM D-396-78, Standard Specifications for Fuel Oils. (40 CFR 60.41 b)

D. Coal

The coal definition is the same as that from 40 CFR 60.41b (NSPS Subpart Db) – Coal means all solid fuels classified as anthracite, bituminous, sub-bituminous, or lignite by the American Society of Testing and Materials in ASTM D388-77, Standard Specification for Classification of Coals by Rank, coal refuse, and petroleum coke. Coal-derived synthetic fuels, including but not limited to solvent refined coal, gasified coal, coal-oil mixtures are also included in this definition.

IV. INITIAL SELECTION PROCESS

A. Initial Review of Data and Reference Material

For each type of fuel category for Fossil Fired Boilers (natural gas, distillate oil, residual oil, and coal) several reference sources were reviewed to determine an initial list of HAPs of Interest. These initial HAP references included: information from the Testing and Monitoring Protocol Work Group (TMPWG), data from API, data from WSPA, Dioxin presentation for the ICCR, AP-42, EPA Emissions Database, EPA MACT floor data presentation to the BWG, EPA Utility Boiler HAPs Study, Great Waters Program documents, EPA's proposed list of 40 priority HAPs for further analyses under the Urban Air Toxic Program, EPA's draft of Prioirty HAPs, and others. Specific references are listed in the document titled *Majority Report on Hazardous Air Pollutants (HAPs) of Concern, Boiler Work Group*, dated February 6, 1998 and in Attachment #2 of the Minority Report entitled *Additional Section 112 (b) and Section 129 Hazardous Air Pollutants of Concern for Industrial Boilers*, dated February 6, 1998. These reports were posted on the TTN by the EPA.

The EPA Utility Boiler HAPs Study can be used as an example of how a list of HAPs of Interest was developed by a particular resource. The EPA reviewed all of the emissions from large fossil fuel fired utility boilers. By modelling the actual emissions, the EPA looked at the health risks. They plugged the emission model information into health effects models to determine the inhalation and cancer risks. From this analysis, the EPA determined which HAPs should be further studied as HAPs of Interest in their Utility HAPs study.

When a HAP was found on multiple resource lists it was further investigated as a HAP of Initial Concern. HAPs not appearing on the various reference lists were not further investigated.

B. <u>Compilation</u> <u>of</u> <u>Emission</u> <u>Data</u>

To further investigate HAPs of Initial Concern various emission databases were reviewed. The emission database references include: EPA Utility Boiler HAPs Study, API/WSPA study, MACT Floor Presentations by the EPA based on the EPA Emissions database, the Fifth Edition of AP-42, EPA Emissions Database, and TMPWG information to mention a few. Again, the specific information can be found in the *Majority Report on Hazardous Air Pollutants (HAPs) of Concern, Boiler Work Group*, dated February 6, 1998 (*Majority HAPs Report)* and in Attachments1,2, and 3 of the report entitled *Additional Section 112 (b) and Section 129 Hazardous Air Pollutants of Concern for Industrial Boilers,* dated February 6, 1998.

All of the emission review data is compiled into tables found in the *Majority HAPs Report.*

Comparisons were then run using the worst emissions or median values from multiple tests (coal) from the various data reference sources. These "worst case" actual emissions were used to determine the total emissions US-wide and to calculate emissions for a 10 million BTU/hour (MMBTU/hr.) boiler, a 100 MMBTU/hr. boiler and a 250 MMBTU/hr. boiler. These boiler sizes were picked because they represent the sizes of typical industrial boilers. These calculated boiler emissions were then used as a standard for comparison against a the screening models, as described below.

V. COMPARISON OF EMISSION DATA TO DEMINIMIS AIR MODEL – INITIAL SCREENING

There was an initial screening performed by comparing the boiler emissions from a 250 MM BTU/hr. boiler with a New Hampshire Department of Environmental Services (NHDES) Deminimis Emission Model. The HAPs Subgroup believed that this conservative model comparison step was a necessary part of the HAPs determination process. From the Model a list of draft deminmis limits was determined by the NHDES. It was believed then, that any emissions that were lower than the NHDES proposed deminimis limits could automatically be dropped from the list of concerns.

This NHDES Screening Model used the following conservative assumptions in a US EPA air pollution dispersion model for a "typical facility with downwash problems":

- Emission rate = 1 lb/hr.
- Stack Height = 10 ft.
- Stack diameter = 1 ft.
- Volume flow = 100 ACFM
- Temperature = 68 degrees F
- Building height = 10 ft., width = 20 ft. and length = 20 ft.

This equates to a stack velocity of about 1 to 2 ft./sec. However, in industry, economic stack velocities usually start at about 10 ft/sec. and can go as high as 100 ft/sec. Typical stack gas velocities are usually more than 20 ft/sec. The temperature in the model stack is only 68 degrees

F. Most industrial boiler stack temperatures are at least 200 to 300 degrees F, even with efficient economizers. A temperature of 68 degrees will cause zero buoyancy of the exiting gas. This type of model would proabably not allow drafting in a boiler.

Basically this model guarantees maximum downstream downwash of any constituents and will predict much higher concentrations of emitted species at the point of impact than would be found under more realistic conditions. Finally, the model deminimis limits were set based on the health effects concentrations that the downstream receptors would encounter.   Then the conservative emission rates were backcalculated.   All of this is discussed to show the conservativeness of the model and the belief that if the actual emissions for a 250 MM BTU/HR. boiler were less than the the deminimis emissions then the HAP would be at low risk for posing any health problem.

Therefore, any HAP whose emissions were below the deminimis levels from the deminimis model were initially considered for dropping from the list HAPs of initial concern.

The emission comparisons are found in the *Majority HAPs Report*.

VI. SECONDARY COMPARISON CONSIDERATIONS

As stated above the NHDES model is an extremely conservative air emission model. This initial model was revised to us more realistic boiler stack parameters and US EPA refined air pollution dispersion models. The boiler stack parameters were derived from an analysis of existing boilers burning oil and wood permitted in New Hampshire. The new stack parameters are shown in a memo from the NHDES dated March 23, 1998 located in Appendix 3.   It should be noted that the model used for the comparison was a dispersion model set up for wood firing conditions. At the time of this screening gas and coal model data were not available. However, in most cases actual boiler groundlevel concentrations used for the comparison were several orders of magnitude below the NHDES second screen wood model emissions.

This comparison was then made with the remaining constituents on the HAPs of Initial Concern list. Those constituents whose emission rates from a 250 MM BTU/hr. boiler were below this second round screening were then dropped or discussed for dropping.

Then the final list of HAPs of Interest was determined. There were several constituents that may have been dropped from one or both screenings but were left on the List of Concern for one of the following reasons:

- Multiple boilers in an area may emit quantities of the HAP that may cause risk to the population,
- The HAP may appear on the proposed Urban Air Toxic list (112[k]) and is at an emission level that may cause some concern (example – Formaldehyde, dioxans/furans)
- The HAP may appear on a list of extreme toxicity (no definition of the limits) and is at an emission rate that may cause some concern.   Additionally the HAP is purported to be a combustion by-product. (Examples- methylene chloride and 1,1,2,2 tetrachloroethane).
- The HAP had little or no emission data.

A set of tables showing each fossil fuel type is shown in Appendix 4. These tables show the rationale for leaving the HAP on the list of HAPs of Concern. It is a summary of the concepts shown above.

VII. CONSENSUS HAPS OF INTEREST LIST

After all of the above screening processes were performed consensus was made within the ad hoc HAPs Subgroup and the BWG at the meeting on April 29, 1998. Below is a list of the HAPs of Interest for each of the fossil fuel groups (gas, distillate oil, residual oil and coal).

Table 1. Gas HAPs of Interest List

Chemical	Chemical
Benzene	Phosphorus
Toluene	Dioxin
Hexane	Cadmium Compounds
POM's	Chromium Compounds
Formaldehyde	Cobalt Compounds
Nickel	Lead Compounds
Acetaldehyde	Manganese compounds
Dibenzofurans	

Table 2. Distillate Oil HAPs of Interest List

Chemical	Chemical
Benzene	Arsenic
1,3 Butadiene	Beryllium
Dioxins/Furans	Cadmium
POM's/Naphthalene	Chromium
Hydrochloric Acid	Lead
Hydrogen Fluoride	Manganese
Formaldehyde	Mercury
Acetaldehyde	Nickel

Table 3. Residual Oil HAPs of Interest List

Chemical	Chemical
Benzene	Arsenic
1,3 Butadiene	Beryllium
Dioxins/Furans	Cadmium
POM's/Naphthalene	Chromium
Hydrochloric Acid	Lead
Hydrogen Fluoride	Manganese
Formaldehyde	Mercury
Selenium	Nickel
	Phosphorus

Table 4. Coal HAPs of Interest List

Chemical	Chemical
Benzene	
Isophorone	Nickel
Dioxins	Phenol
POMs	Selenium
Hydrochloric Acid	Cyanide
Hydrogen Fluoride	Acrylamide
Acetaldehyde	Acrylonitrile
Acrolein	2-chloro-acetophone
Arsenic	Ethylene Dibromide
Beryllium	Formaldehyde
Cadmium	Hexachlorobenzene
Chromium	Methyl Chloride
Cobalt	Methyl Iodide
Lead	N-Nitrosodimethylamine
Phosphorus	1,1,2,2 Tetrachloroethane
Manganese	Antimony Compounds
Mercury	Radionuclides

APPENDIX 1

MERCURY IN WELLHEAD GAS

6/9/98-draft

MERCURY IN WELLHEAD GAS

Finding – Mercury emissions from wellhead gas combustion are insignificant nationwide, and even in those remote geographical areas with the highest mercury concentrations, emissions are about two pounds a year or less.

Wellhead Gas

"Wellhead"[5] gas is natural gas produced directly from underground reservoirs without having removed the natural gas liquids (butane, propane, gasoline, etc.). The Btu content of this gas can range as high as 1200 Btu as compared to approximately 1000 Btu for natural gas being transported to market via Department of Transportation (DOT) regulated pipelines.

"Natural gas", as discussed in this Section III B of this document, is pipeline quality gas located downstream of the natural gas plant. Wellhead gas is processed and the natural gas liquids are removed to produce marketable natural gas. Testing by the Gas Research Institute (GRI) of natural gas demonstrates it has only a trace mercury concentration as noted in GRI's Report[3]. The maximum mercury concentration found in natural gas was 0.2 micrograms per cubic meter (ug/m^3).

Wellhead gas is only used as fuel in oil and gas industry operations where processed gas cannot be obtained from a natural gas plant. This lack of processed gas could be due to the absence of a DOT regulated pipeline to market or the remaining gas in the producing field is depleted to such an extent that the gas plant has been shut down due to economic considerations. Wellhead gas can be used in boilers, heater treaters, or IC engines at isolated oil and gas field locations.

Boilers are rarely used at oil and gas facilities outside of California. Boilers are used in California for generating steam for injection into high viscous oil reservoirs for recovery purposes. Nearly all of the boilers in California use natural gas with a few using wellhead gas. Mercury is not found in California wellhead gas above trace quantities (1-100 ug/m^3).

Heater treaters and IC engines use wellhead gas at certain oil and gas facilities nationwide. The only know geographical area with mercury greater than 100 ug/m^3 is in South Texas (2-3 County Area)[4].

Mercury in Wellhead Gas

Elemental mercury[1] was found in wellhead gas as early as 1969 in Holland. In addition, mercury corrosion was detected in an aluminum spiral wound heat exchanger at a liquid natural gas plant in Skikda, Algeria in 1974. Since this time, mercury in wellhead gas has become a major concern in cryogenic gas processing industries. These industries often use aluminum heat exchangers in their processes. Mercury corrosion of aluminum exchangers has led to several equipment failures since the problems at Skikda.

Mercury forms[1] are present in some wellhead gas and wellhead gas associated condensates, as organometallic and inorganic compounds, and in the elemental (metallic) form depending on the origin of the gas. The elemental form can be found in either the vapor or liquid phase. The organometallic and inorganic compounds drop into the liquid phase in any fractionation of the natural gas streams. Vapor phase elemental mercury is a primary culprit in corrosion of aluminum exchangers inside cryogenic cold boxes. Operators typically remove mercury upstream of the natural gas plant to prevent corrosion of aluminum equipment within the plant as well as prevent corrosion at facilities downstream of the plant. Mercury is not removed from wellhead gas combusted at production sites.

Mercury has been found in wellhead gas at a few geographic locations nationwide. Mercury concentrations range from 0.02 – .40 micrograms per cubic meter in the Gulf Coast Area[2]; 5 – 15 micrograms per cubic meter in the Overthrust Belt/Kansas[2,4]; and as high as 500 micrograms per cubic meter in some South Texas fields[4]. Gas plant operators test for mercury because cryogenic fractionation processes can be damaged by mercury concentrations as low as 1-10 micrograms per cubic meter. Operators utilize different processes worldwide to remove mercury from the plant inlet gas stream to protect sensitive components from corrosion. Again, the mercury removal systems are intended to protect the process equipment in the gas processing plant; they have nothing to do with improving combustion. In fact, most cryogenic plant operators do not find it necessary to remove trace mercury concentrations from wellhead gas to prevent corrosion.

Wellhead Gas as Fuel

For the purposes of Combustion MACT, there are three main reasons why mercury in wellhead gas is not significant.:

1. Wellhead gas is nearly always used in oil and gas operations upstream of the natural gas plant. The typical type of equipment used in these operations is small and widely separated geographically. Nearly all heaters are smaller than 3 MMBTU/Hr. and most internal combustion engines are less than 1000 horsepower in size. Most of these production facilities will not have more than one of these emission sources per site.

2. Concentrations of mercury in produced wellhead gas are very low in the United States. Mercury concentrations range from 0.02 micrograms per cubic meter to 500 micrograms per cubic meter. Consequently, annual emissions of mercury from typical oil and gas production equipment are very low as calculated[6] in the following tables:

Gulf of Mexico (0.4 ug/m^3 mercury in wellhead gas)

Equipment Size	Pounds/Yr.	Tons/Yr.
3 Million BTU Heater	0.00066	3.31×10^{-7}
1000 HP IC Engine	0.00187	9.36×10^{-7}

Overthurst Belt/Kansas (15 ug/m^3 mercury in wellhead gas)

Equipment Size	Pounds/Yr.	Tons/Yr.
3 Million BTU Heater	0.025	1.26×10^{-5}
1000 HP IC Engine	0.070	3.51×10^{-5}

South Texas (500 ug/m^3 mercury in wellhead gas)

Equipment BTU Heater	Pounds/Yr.	Tons/Yr.
3 Million BTU Heater	0.820	4.10×10^{-4}
1000 HP IC Engine	2.320	1.16×10^{-3}

Note: These emission calculations assume that the total mercury in the fuel gas is emitted to the atmosphere after combustion; leading to a potential overestimate. In addition, the mercury estimates may be high because they are based on pure methane combustion which has a lower Btu value resulting in a higher fuel throughput.

3. Wellhead gas containing more than trace concentrations of mercury is only found in South Texas. In this geographical area, oil and gas production facilities are generally located in arid and rural areas.

REFERENCES

1. Rios, Julio A., Coyle, David A., Durr, Charles A. and Frankie, Brian M. "Removal of Trace Mercury Contaminants from Gas and Liquid Streams in the LNG and Gas Processing Industry", 77th Annual Convention, Gas Producers Association, March 16-18, 1998.

2. "GRI Mercury Removal Technology (Hgone) Process Design and Engineering", Vol.1, Gas Research Institute Report 96/0018.1, 1995.

3. "Characterization and Measurement of Natural Gas Trace Constituents Volume II: Natural Gas Survey", Gas Research Institute 94/0243.2, 1995.

4. Lewis, Larry L., "Measurement of Mercury in Natural Gas Streams" in the 77th Annual Convention, Gas Producers Association, 1995.

5. "Field Handling of Natural Gas", Third Edition, Natural Gas Processors Association, 1972.

6. McCarthy, James, "Interoffice Memo to Bob Welch, Columbia Gas, and Bill Freeman, Shell – ICCR Question on Mercury in Unprocessed Gas", March 7, 1998.

APPENDIX 2

Boilers Working Group - MACT Floor Documentation
Rationale for Broad Definition of Gaseous Fuels

Boilers Working Group - MACT Floor Documentation
Rationale for Broad Definition of Gaseous Fuels

BACKGROUND

Emissions data on HAPs and criteria pollutants used in the MACT determination process originated from several sources, and have gone through several stages of screening and assessment, as described in the Boilers Working Group “HAPs of Interest Analysis”. For gas-fired external combustion devices (i.e. Boilers and Process Heaters) three primary sources were utilized.

First, source test results collected under the California Air Toxics "Hot Spots" Inventory and Assessment Act (AB2588) have been compiled and quality reviewed in a joint effort by the Western States Petroleum Association (WSPA), the California Air Resources Board (CARB), and the American Petroleum Institute (API). The results of this investigation are compiled in the 3-volume Draft Report titled "Development of Toxics Emission Factors for Petroleum Industrial Combustion Sources" (D. W. Hansell and G. C. England, EER Corporation, September 1997). It was provided to the US EPA in October 1997, and is available in the ICCR docket. A presentation on this database was provided to a joint meeting of all the ICCR Work Group members on November 18, 1997. The validation and verification processes used to quality assure these data makes this the most reliable and comprehensive compilation of field emission source test data for petroleum industry combustion sources. The final report is currently being printed by API (August 1998) and will be available to the Coordinating Committee and the US EPA by mid-September.

The second source of emissions test data came from the Petroleum Environmental Research Forum (PERF) 92-19 "Toxic Combustion Byproducts" project. In 1992 PERF initiated a Cooperative Research and Development Agreement (CRADA) with the U.S. Department of Energy, and with EPA participation, performed an experimental and fundamental investigation of chemical and physical mechanisms governing organic HAP formation, destruction, and emissions. These tests on full-scale burners were performed at the Sandia National Laboratories/Livermore. This program produced data of very high quality that shed light on many of the key questions surrounding the field data. The results of this project were presented to the Coordinating Committee on July 22, 1997, and are summarized in a paper titled "Organic Hazardous Air Pollutant Emissions from Gas-Fired Boilers and Process Heaters" (G.C. England and D.W.Hansell, EER Corporation, July 1997) which is available in the ICCR docket. The PERF 92-19 CRADA Final Report, "The Origin and Fate of Toxic Combustion Byproducts in Refinery Heaters: Research to Enable Efficient Compliance with the Clean Air Act" (August 5, 1997), and be accessed at http://www.epa.gov/ttn/iccr/dirss/perfrept.pdf. The complete 10-volume study including test reports and appendices has been placed in the ICCR docket.

Lastly, the ICCR Emissions Database, V.2, provides a compilation of emissions test data made available from existing electronic databases such as STIRS, and other information from state and local agencies. Emissions information collected from the 114 ICR survey was also added to this database.

CONCLUSIONS

Based on the discussion above and the references cited therein, we conclude that:

HAP emissions from all gas-fired sources are generally very low, but exhibit inherent variability associated with process fluctuations and sampling and analysis uncertainties.

The PERF data referenced above demonstrate that HAP emissions from typical industry gas fired burners, under a variety of operating conditions are all very low, at or near the detection limits of the best measurement methods. In addition, field source test data, such as the WSPA/API database indicate that annual total HAP emissions from operating gas-fired heaters and boilers are well below the major source definition.

HAP emissions from devices fired by either natural gas or petroleum processing derived gas are similar, on a Btu basis.

The controlled laboratory testing (PERF study) and the WSPA/API field test data demonstrate that emissions factors derived independently for different gaseous fuels are indistinguishable, when measurement uncertainty and process variability are taken into account (Figures 1). The emission factor derivation process accounts for the different heat content of the variety of the gases used in practice, and which like natural gas, consist primarily of hydrocarbons mixtures.

HAP emissions from gas-fired boilers and process heaters are equivalent.

Design practices are such that the same burner types are used for constructing both gas-fired process heaters and boilers. In addition, the field emissions data for boilers and process heaters, fired by a variety of gaseous and liquid fuels, was shown to be similar (Figure 2). The data demonstrate that emissions from boilers or process heaters vary by size (heat input) but are otherwise expected to be equivalent.

RECOMMENDATIONS

For the purposes of subcategorizing boilers – it is recommended that a single subcategory be established for devices firing the following gaseous fuels:

1. *Natural Gas/Wellhead Gas:* a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane;

2. *Liquid Petroleum Gas:* as defined by the American Society of Testing and Materials in ASTM D1835-82, Standard Specification for Liquid Petroleum gases.

3. *Petroleum Derived Gas:* Gaseous fuel derived from the processing of crude oil, petroleum, or petrochemicals.

Since consistent definitions of the fuels combusted are desirable for all ICCR sources, we recommend that the Coordinating Committee adopt the three-part definition above which is consistent with that adopted by both the Process Heaters and Turbines Working Groups for their gaseous fired devices.

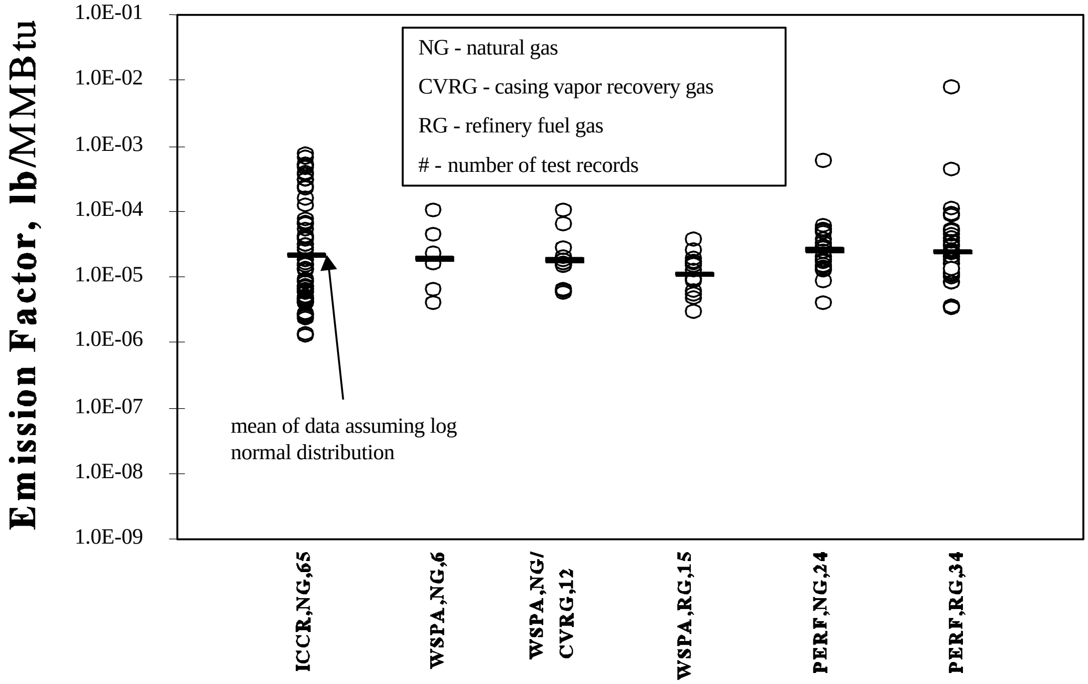
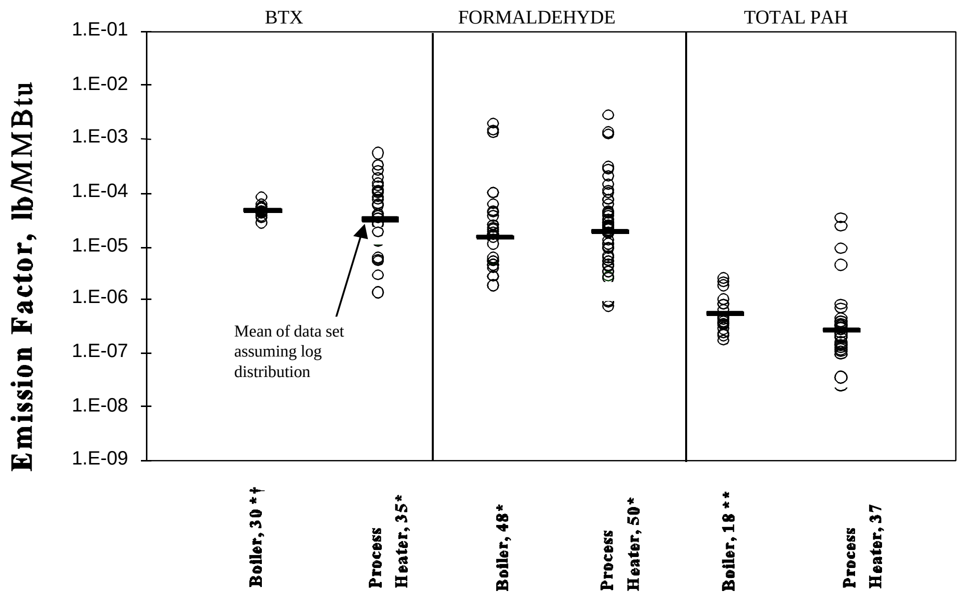


Figure 1. Formaldehyde emissions as a function of fuel type for gas fuel fired boilers (ICCR, WSPA, and PERF data).



* Includes crude, FO #6, and gaseous fuel (primarily gas)

** Includes FO #6 and gaseous fuel (primarily gas)

† Number following label = number of test records

Figure 2. Comparison of HAP emissions data for Boilers and Process Heaters (WSPA data).

APPENDIX 3

ICCR Modeling for Hypothetical Oil and Wood Boilers From the New Hampshire Dept. of Environmental Services

STATE OF NEW HAMPSHIRE
IntraOffice Memorandum

Department of Environmental Services
Air Resources Division

TO: Andy Bodnarik, Administrator, Engineering Bureau — DATE: March 23, 1998

FROM: Jim Black, Modeling Supervisor, Technical Services Bureau

SUBJ: ICCR Modeling for Hypothetical Oil and Wood Boilers

Based on our discussions of March 18 regarding the modeling of hypothetical oil and wood fired boilers, I have completed a set of screening and refined modeling runs. Runs were made for flat, complex and simple terrain, assuming relatively hilly terrain in the latter two cases. Both annual and 24-hour average concentrations were calculated. The following inputs were used:

Parameter	**Oil Condition**	**Wood Condition**
Stack Height	200 ft	180 ft
Stack Diameter	9 ft	7.5 ft
Volume Flow	150,000 ACFM	125,000 ACFM
Gas Temperature	350^{o} F	330^{o} F
Emission Rate	1 lb/hr	1 lb/hr
Building Height	90 ft	90 ft
Building Width	80 ft	80 ft
Building Length	80 ft	80 ft

The above inputs were derived from a study of large boilers burning both oil and wood which have been permitted in this state. The building data are representative of a typical boiler building for facilities which have previously been modeled. Using this size building, small but measurable downwash effects were predicted.

For the simple terrain modeling, gradually rising terrain was assumed in all directions, typical of a valley situation with surrounding rising hills. Elevations were assumed to reach stack top just beyond one kilometer and plume height close to three kilometers. This is conservative, though not unrealistic, topography and, in conjunction with the flat terrain modeling, presents a full range of terrain conditions.

Using the above input data, the following maximum impacts were predicted:

Maximum 24-Hour Average Concentrations

	Oil Condition			**Wood Condition**		
Screening Impact (ug/m^3)	0.13	**0.47**	0.23	0.21	**0.68**	0.31
Distance (m)	990	1200 (a)	3000 (b)	270	1100 (a)	2500 (b)
Refined Impact (ug/m^3)	0.12	**0.30**	(c)	0.18	**0.42**	(c)
Distance (m)	300	300		300	1000	

Maximum Annual Average Concentrations

	Oil Condition			**Wood Condition**		
Screening Impact (ug/m^3)	0.033	**0.118**	0.058	0.053	**0.170**	0.078
Distance (m)	990	1200 (a)	3000 (b)	270	1100 (a)	2500 (b)
Refined Impact (ug/m^3)	0.008	**0.029**	(c)	0.017	**0.047**	(c)
Distance (m)	300	2000		300	1000	

Notes: (a) stack top height was assumed to be reached at this distance
(b) plume height was assumed to be reached at this distance
(c) modeled in conjunction with simple terrain (maximum impacts)

Please contact me if you have any questions regarding the results.

c: C. Beahm

APPENDIX 4

Rationale for Selection of Fossil Fuel HAPs

Table A – Gas HAPs of Interest

Table B – Distillate Oil HAPs of Interest

Table C – Residual Oil HAPs of Interest

Table D – Coal HAPs of Interest

TABLE A. SELECTION RATIONALE - GAS HAPS OF INTEREST

Classification	Component	NHDES De minimis (1)	NHDES Indust. Model (2)	Urban Air Toxics List (3)	Great Lakes Stretegy/ Great Waters (4)	Health Risk in Detroit (5)	Highly Toxic HAP (6)	Not Enough Data	Other
Volitiles	Benzene	X		X		X			
	Toluene								O3 Precursor
	Hexane	X	Not Modeled					X	
Semi Volatiles	POMs			X	X	X	X		
Carbonyls	Acetaldehyde			X					
	Formaldehyde	X		X		X			
Metals	Cadmium	X		X		X	X		
	Chromium	X		X		X	X		
	Cobalt	X			X				
	Lead	X		X	X	X	X		
	Manganese	X		X	X	X	X		
	Nickel	X		X	X	X	X		
Other	Dibenzofurans	ND	N/A	X	X	X	X	X	X
	Dioxins	ND	N/A	X	X	X	X	X	X
	Phosphorus	X	Not Modeled						

TABLE A. SELECTION RATIONALE - GAS HAPS OF INTEREST (Continued)

(1) Comparison with conservative NHDES Model (250 MM BTU/Hr. boiler Comparison).
(2) Comparison with industrial NHDES Model (250 MM BTU/Hr. boiler Comparison). Only model data comparison available was for wood boiler emissions.
(3) Hazardous Air Pollutant Area Source Program (CAA Subsect. 112(k) - Urban Air Toxics Study Priority HAP List of 40
(4) Listed on one or more of the following Great Lakes Area Programs:
Great Waters Progam, CAA Subsect. 112(m)
Great Lakes Binational Toxics Strategy, International Joint Commission, *Focu*, Vol. 22, Issue 2, 1997
Critial Pollutant from EPA Revised Draft of Lake Michigan Lakewide Management Plan For Tox. Pollutants, 8/30/93
Great Lakes Commissions, Great Lakes Regional Air Toxics Emissions Inventory of 49 Targeted Compounds
(5) Health Risk in Detroit - Ref. The Transboundary Air Toxics Study, EPA Final Summary Report, Dec. 1990
(6) Highly Toxic HAP's (Potency), Ref. EPA's Draft of Priority HAP's (5/13/97)
N/D - Not enough Data
N/A - Not Applicable

TABLE B. SELECTION RATIONALE - DISTILLATE OIL HAPs OF INTEREST

Classification	Component	NHDES De minimis (1)	NHDES Indust. Model (2)	Urban Air Toxics List (3)	Great Lakes Stretegy/ Great Waters (4)	Health Risk in Detroit (5)	Highly Toxic HAP (6)	Not Enough Data	Other
Volatiles	Benzene	X(1a)	(1a)	X		X			
	1,3 Butadiene	1(a)	Not Modeled	X					
Semi Volatiles	Dioxins/Furans	ND	N/A	X	X	X	X	X	
	POMs/naphthalene	ND	N/A	X	X	X	X		
Acid Gases	Hydrochloric acid	ND						X	
	Hydrogen fluoride	ND	N/A					X	
Aldehydes/ketones	Formaldehyde			X		X			
	Acetaldehyde	1(A)		X				X	
Metals	Arsenic	X		X		X	X		
	Beryllium	X		X		X	X		
	Cadmium	X		X		X	X		
	Chromium	X		X		X	X		
	Lead	X		X	X	X	X		
	Manganese	X		X	X	X	X		
	Mercury	X		X	X	X	X		
	Nickel	X		X	X	X	X		

(1) Comparison with conservative NHDES Model (250 MM BTU/Hr. boiler Comparison)
(1a) Compound Values assumed the same as for Gas. According to PERF Analysis and Report.

TABLE B. SELECTION RATIONALE - DISTILLATE OIL HAPs OF INTEREST (Continued)

(2) Comparison with industrial NHDES Model (250 MM BTU/Hr. boiler Comparison). Only model data comparison available was for wood boiler emissions.
(3) Hazardous Air Pollutant Area Source Program (CAA Subsect. 112(k) - Urban Air Toxics Study Priority HAP List of 40
(4) Listed on one or more of the following Great Lakes Area Programs:
Great Waters Progam, CAA Subsect. 112(m)
Great Lakes Binational Toxics Strategy, International Joint Commission, *Focus*, Vol. 22, Issue 2, 1997
Critial Pollutant from EPA Revised Draft of Lake Michigan Lakewide Management Plan For Tox. Pollutants, 8/30/93
Great Lakes Commissions, Great Lakes Regional Air Toxics Emissions Inventory of 49 Targeted Compounds
(5) Health Risk in Detroit - Ref. The Transboundary Air Toxics Study, EPA Final Summary Report, Dec. 1990
(6) Highly Toxic HAP's (Potency), Ref. EPA's Draft of Priority HAP's (5/13/97)
ND - Not enough Data
N/A - Not applicable

TABLE C. SELECTION RATIONALE - RESIDUAL OIL HAPs OF INTEREST

Classification	Component	NHDES De minimis (1)	NHDES Indust. Model (2)	Urban Air Toxics List (3)	Great Lakes Stretegy/ Great Waters (4)	Health Risk in Detroit (5)	Highly Toxic HAP (6)	Not Enough Data	Other
Volatiles	Benzene	X		X		X			
	1,3 Butadiene	ND	N/A	X				X	
Semi Volatiles	POMs/naphthalene	ND	N/A	X	X	X	X	X	
Acid Gases	Hydrochloric acid	X							
	Hydrogen fluoride	X							
Aldehydes/ketones	Formaldehyde	X		X		X			
Metals	Arsenic	X		X		X	X		
	Beryllium	X		X		X	X		
	Cadmium	X		X		X	X		
	Chromium	X		X		X	X		
	Lead	X		X	X	X	X		
	Manganese	X		X	X	X	X		
	Mercury	X		X	X	X	X		
	Nickel	X		X	X	X	X		
	Selenium	X				X			
	Phosphorus	X							
Other	Dioxins/Furans	ND	N/A	X	X	X	X	X	

TABLE C. SELECTION RATIONALE - RESIDUAL OIL HAPs OF INTEREST (Continued)

(1) Comparison with conservative NHDES Model (250 MM BTU/Hr. boiler Comparison)
(2) Comparison with industrial NHDES Model (250 MM BTU/Hr. boiler Comparison). Only model data comparison available was for wood boiler emissions.
(3) Hazardous Air Pollutant Area Source Program (CAA Subsect. 112(k) - Urban Air Toxics Study Priority HAP List of 40
(4) Listed on one or more of the following Great Lakes Area Programs:
Great Waters Progam, CAA Subsect. 112(m)
Great Lakes Binational Toxics Strategy, International Joint Commission, *Focu*, Vol. 22, Issue 2, 1997
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Great Lakes Commissions, Great Lakes Regional Air Toxics Emissions Inventory of 49 Targeted Compounds
(5) Health Risk in Detroit - Ref. The Transboundary Air Toxics Study, EPA Final Summary Report, Dec. 1990
(6) Highly Toxic HAP's (Potency), Ref. EPA's Draft of Priority HAP's (5/13/97)
ND - Not enough Data
N/A - Not Applicable

TABLE D. SELECTION RATIONALE - COAL HAPS OF INTEREST

CAS Number	Chemical Name	NHDES De minimis (1)	NHDES Indust. Model (2)	Urban Air Toxics List (3)	Great Lakes Stretegy/ Great Waters (4)	Health Risk in Detroit (5)	Highly Toxic HAP (6)	Not Enough Data	Other
75070	Acetaldehyde			X					
107028	Acrolein			X			X		
79061	Acrylamide	X	Not Modeled	X		X	X		
107131	Acrylonitrile	X		X		X	X		
71432	Benzene	X		X		X			
2142689	2-chloro acetophenone	X	Not Modeled						
106934	Ethylene dibromide (Dibromoethane)			X		X	X		
50000	Formaldehyde	X		X		X			
118741	Hexachlorobenzene	X	Not Modeled		X		X		
7647010	Hydrochloric acid	X	Not Modeled						
7664393	Hydrogen fluoride (Hydrofluoric acid)	X	Not Modeled						
78591	Isophorone								
74873	Methyl chloride (Chloromethane)			X		X			
74884	Methyl Iodide	ND	N/A					X	
62759	N-Nitrosodimethylamine	X	Not Modeled						
108952	Phenol				X				
7723140	Phosphorus	X	Not Modeled						
79345	1,1,2,2-Tetrachloroethane			X					
0	Antimony Compounds	X							
0	Arsenic Compounds	X		X		X	X		
0	Beryllium Compounds	X		X		X	X		

TABLE D. SELECTION RATIONALE - COAL HAPS OF INTEREST (Continued)

CAS Number	Chemical Name	NHDES De minimis (1)	NHDES Indust. Model (2)	Urban Air Toxics List (3)	Great Lakes Stretegy/ Great Waters (4)	Health Risk in Detroit (5)	Highly Toxic HAP (6)	Not Enough Data	Other
0	Cadmium Compounds	X		X		X	X		
0	Chromium Compounds	X		X		X	X		
0	Cobalt Compounds	X			X				
0	Cyanide Compounds1	X	Not Modeled						
0	Lead Compounds	X		X	X	X	X		
0	Manganese Compounds	X		X	X	X	X		
0	Mercury Compounds	X		X	X	X	X		
0	Nickel Compounds	X		X	X	X	X		
0	Polycylic Organic Matter (POM)	ND	N/A	X	X	X	X	X	
0	Radionuclides	X	Not Modeled						On EPA Utility Coal HAPs for further Study
0	Selenium Compounds	X				X			
	Dioxins	ND	N/A	X	X	X	X	X	

TABLE D. SELECTION RATIONALE - COAL HAPS OF INTEREST (Continued)

(1) Comparison with conservative NHDES Model (250 MM BTU/Hr. boiler Comparison)
(2) Comparison with industrial NHDES Model (250 MM BTU/Hr. boiler Comparison). Only model data comparison available was for wood boiler emissions.
(3) Hazardous Air Pollutant Area Source Program (CAA Subsect. 112(k) - Urban Air Toxics Study Priority HAP List of 40
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(5) Health Risk in Detroit - Ref. The Transboundary Air Toxics Study, EPA Final Summary Report, Dec. 1990
(6) Highly Toxic HAP's (Potency), Ref. EPA's Draft of Priority HAP's (5/13/97)
ND - Not enough data in emission database.
N/A - Not Applicable

Attachment 9

Combustion Turbine Work Group Presentation on Cost of HAP Emission Controls

Closure Item

Combustion Turbine Work Group

Cost-Effectiveness of Oxidation Catalyst Control of Hazardous Air Pollutant Emissions From Combustion Turbines (for Existing Combustion Turbines Using Natural Gas as Fuel)

Presentation to the ICCR Coordinating Committee

September 16, 1998

Summary

- Paper documents CTWG consensus views on reasonable lower-range estimates of the cost-effectiveness of oxidation catalysts for HAPs control, based on available information

- Complicating factors identified & discussed in paper would tend to increase the costs

- CTWG recommends that the CC forward the materials to EPA and recommend that EPA consider the information in evaluating above-the-floor MACT options for existing combustion turbines

Approach

1 Use available information & build on earlier GRI and EPA work on cost-effectiveness

2 Address 3 quantitative components of cost-effectiveness

- baseline emissions, costs, & catalyst performance

3 Develop quantitative lower-range estimates for base case using 7 model turbines (1.13 to 170 MW)

- include cases to document effects of:
  - » emissions variability (highest & average emission rates)
  - » catalyst performance variability (80% and 50% reduction)
  - » costs associated with catalyst life variability (3-yr and 6-yr life)

4 Identify and discuss complicating factors

Baseline Emissions (1)

- **Average EFs and highest EFs presented in paper**
- **Database Criteria:**
  - ⇨ **only natural gas (42 tests)**
  - ⇨ **only tests that met QA\QC (8 tests disqualified)**
  - ⇨ **test at greater than 80% load (11 tests disqualified)**
- **23 tests used for baseline (tests per HAP varies)**
- **Formaldehyde comprises about 70% of total HAPs**

ICCR Emissions Database
Average Emission Factors

Pollutant	Emission Factor (lb/MMBtu)	Number of Tests
Formaldehyde	7.13E-04	22
Acetaldehyde	9.12E-05	7
Acrolein	5.49E-06	2
Benzene	1.03E-05	11
Toluene	1.42E-04	7
Ethylbenzene	4.10E-05	1
Xylenes	4.59E-05	5
PAHs	2.23E-06	4
Naphthalene	1.46E-06	3

Baseline Emissions (2)

Complicating Factors:

- Compilation of highest EFs from different tests results in "worst of the worst" EFs
- HAP emissions may be different for fuels other than natural gas
- Few (or single) tests for some pollutants
- Baseline emissions underestimated for turbines that operate at less than 80% load, since higher emission rates may occur at low loads

Oxidation Catalyst Costs (1)

- Sources of information on costs:
  - Quotes provided to EPA by catalyst vendors
  - Costs gathered by the Gas Research Institute
  - Estimates provided by Work Group members
- CTWG used cost methodology included in the EPA's OAQPS Control Cost Manual
- CTWG developed following cost estimates:
  - Oxidation catalyst costs
  - Catalyst housing costs
  - Contingency costs
  - Catalyst & equipment life
  - Catalyst disposal costs
  - Operating costs
  - Maintenance costs
  - Fuel penalty costs
  - Compliance test costs

Oxidation Catalyst Costs (2)

Complicating Factors

- Limited information on oxidation catalysts
  - Cost formula based on 1 vendor's quotes
  - Industry/vendor experience for CO, not HAPs
  - Limited information on catalyst life & performance degradation
- No costs for site installation complications in base case
- Performance testing costs underestimated
  (especially for small turbines)
- Back pressure power loss, fuel penalty
  - No costs for power loss in base case
  - Variables in fuel penalty may increase costs
- Only basic parameter monitoring and an annual stack test included as compliance monitoring

HAPs Reduction Performance (1)

- Data Sources
  - Limited data from 2 emissions tests
    - » API\GRI\SoCal and SCONOX^{TM}
  - Engineering Judgement / Literature
    - » Per Engelhard, if CO control at 90%, then Formaldehyde ≈ 80%
- Base Cases Adopted:
  - 80% HAPs reduction performance, 6-yr “typical” life
  - 80% HAPs reduction performance, 3-yr guaranteed life
  - 50% HAPs reduction performance, 6-yr “typical” life
    - » Allows insight on effects of performance degradation or lower overall HAPs reduction performance

HAPs Reduction Performance (2)

Complicating Factors

- Uncertainty about HAPs performance
  - No emissions data to confirm 80% or 50% assumptions
- Performance degradation over time
- Different HAPs reduction performance for various HAPs not reflected in analysis
  - Assumed same control efficiency for all HAPs
  - Control efficiency will likely decrease for larger molecules
  - No emissions data to confirm

Cost-Effectiveness Results

Cost-Effectiveness
($ per Mg Total HAPs)

- Average EF, 80% control, 6-yr life

Model Turbine		Cost Effectiveness ($/Mg total HAPs)
Model 1	85.4 MW	$380,000
Model 2	170 MW	$270,000
Model 7	39.6 MW	$440,000
Model 9	27 MW	$430,000
Model 13	3.5 MW	$1,700,000
Model 15	9 MW	$840,000
Model 17	1.13 MW	$4,100,000

- **Paper includes:**
  - » **Breakdown of costs**
  - » **$ / Mg for all cases**
- **High/Low Range for Other Cases Analyzed:**
  - » **1.1 MW, 50% reduction, 6 year life, average EF**
    - **$6,600,000 per Mg HAP**
  - » **170 MW, 80% reduction, 6 year life, high EF**
    - **$41,000 per Mg HAP**

Conclusions

- Paper presents 6 base case costs for all 7 model turbines (1.13 MW to 170 MW) to document the effects of:
  - emissions variability (highest & average emission rates)
  - catalyst performance variability (80% and 50% reduction)
  - costs associated with catalyst life variability (3-yr and 6-yr life)
- Complicating factors not quantified would tend to *increase* the cost per ton of HAPs reduction
- CTWG agrees that the base case analyses represent reasonable *lower range* estimates of the cost per metric ton of HAPs reduction for the use of oxidation catalysts on combustion turbines to reduce HAPs

Recommendations

- CTWG recommends that:
  - Coordinating Committee forward the paper on cost-effectiveness to EPA, and
  - Coordinating Committee recommend that EPA consider the information in the paper as a part of the Agency's assessment of above-the-floor MACT options for existing combustion turbines

Attachment 10

Paper on Cost of HAP Emission Controls for Combustion Turbines (Closure Item)

MEMORANDUM:

DATE: 4 September 1998

SUBJECT: Cost-Effectiveness of Oxidation Catalyst Control of Hazardous Air Pollutant (HAP) Emissions From Stationary Combustion Turbines

FROM: Combustion Turbine Work Group

TO: ICCR Coordinating Committee

The Combustion Turbine Work Group (CTWG) formed a task group to develop a white paper on the cost-effectiveness of oxidation catalysts in controlling HAP emissions from combustion turbines. The attached document is the white paper developed by this task group.

The CTWG concurs that this information may be valuable to EPA in developing regulations for combustion turbines and requests that the ICCR Coordinating Committee pass it to EPA as a Closure Item.

Attachment: Cost-Effectiveness of Oxidation Catalyst Control of Hazardous Air Pollutant (HAP) Emissions From Stationary Combustion Turbines

Cost-Effectiveness of Oxidation Catalyst Control of Hazardous Air Pollutant (HAP) Emissions From Stationary Combustion Turbines

Prepared By the

Combustion Turbine Work Group
Of the Industrial Combustion Coordinated Rulemaking

September 4, 1998

Table of Contents

I. INTRODUCTION

This paper presents the assessment of the Combustion Turbine Work Group (CTWG) with regard to the potential cost-effectiveness of oxidation catalysts used to control hazardous air pollutant (HAP) emissions from combustion turbines. This assessment is made in the context of the Coordinating Committee providing recommendations that contribute to EPA's evaluation of "above-the-floor" MACT options for existing combustion turbines. In accordance with Section 112(d) of the Clean Air Act, EPA must consider costs in evaluating above-the-floor options for MACT, along with any non-air quality health and environmental impacts and energy requirements.

In previous materials, the Coordinating Committee recommended to EPA, based on available information, that it is not possible to identify a best performing subset of existing combustion turbines, and as a result, there is no MACT floor for the existing population of combustion turbines in the United States. Therefore, to determine MACT, EPA may evaluate emission reduction technologies above the floor for existing combustion turbines. The CTWG has reviewed emission reduction technologies for existing turbines to identify controls that may be considered in the above-the-floor MACT analysis. Based on the CTWG's review, oxidation catalysts for the reduction of carbon monoxide (CO) may reduce emissions of organic HAPs from combustion turbines. The CO oxidation catalyst is an add-on control device that is placed in the turbine exhaust duct and serves to oxidize CO and hydrocarbons to H_2O and CO_2. The catalyst material is usually a precious metal (platinum, palladium, or rhodium). The oxidation process takes place spontaneously, without the requirement for introducing reactants (such as ammonia) into the fuel gas stream (EPA, 1993a). Oxidation catalysts are used on turbines to achieve control of CO emissions, especially turbines that use steam injection, which can increase the concentrations of CO and unburned hydrocarbons in the exhaust (EPA 1993a, Chen et al., 1993). Therefore, EPA may evaluate oxidation catalysts as an "above-the floor" MACT option for existing combustion turbines. This paper addresses the costs and the HAP air emissions reductions that may be achieved with oxidation catalysts. The CTWG recognizes that EPA may consider other factors, such as non-air quality environmental impacts, energy requirements, and secondary pollutants, in assessing above-the-floor MACT

The approach taken in this paper is to present a base case quantitative estimate of the cost-effectiveness of oxidation catalysts for model combustion turbine units, which range in size from 1.13 megawatts (MW) to 170 MW. To determine cost-effectiveness for the base case analysis, the CTWG developed quantitative estimates for the three inputs required to estimate cost-effectiveness:

1. the baseline HAP emissions of combustion turbines before emissions control,

2. the costs of acquiring and operating oxidation catalysts, and,

3. the performance of oxidation catalysts in reducing HAP emissions.

For each of these inputs this paper presents the key factors that the CTWG considers important. In assessing these three areas the CTWG presents a base case quantitative estimate of the cost-effectiveness of oxidation catalysts for each model turbine. The quantitative cost-effectiveness for each model was calculated by dividing the total annual cost by the mass of annual HAP emission reductions. Cost-effectiveness is expressed as dollars per megagram of HAP emission reduction. A megagram (Mg) is one metric ton, or approximately 1.1 U.S. tons. The paper also presents a qualitative discussion of the CTWG's views on complicating factors that could cause the estimated cost-effectiveness base case to be different in real-world situations.

Section II provides a summary of the base case assumptions. Sections III, IV, and V present the quantitative estimates and complicating factors for each of the three inputs for cost-effectiveness: baseline HAP emissions, control costs, and emission reduction. The range of cost-effectiveness values and the base case cost-effectiveness for each model turbine are presented in Section VI. The CTWG’s conclusions and recommendations are presented in Section VII.

II. SUMMARY OF BASE CASE ASSUMPTIONS

For the base case cost-effectiveness analysis, the CTWG selected seven model turbines that range in size from 1.13 megawatts (MW) to 170 MW:

- Model 1 -- GE PG 7121EA, 85.4 MW

- Model 2 -- GE PG 7231FA, 170 MW
- Model 7 -- GE PG 6561B, 39.6 MW
- Model 9 -- GE LM2500, 27 MW
- Model 13 -- Solar Centaur 40, 3.5 MW
- Model 15 -- Solar Mars T12000, 9 MW
- Model 17 -- Solar Saturn T1500, 1.13 MW

These seven model turbines were selected from the 32 model turbines developed by the CTWG to provide the basis to estimate the national impacts associated with any future combustion turbine MACT standard. A complete list of the 32 model turbines is provided as **Appendix A.**

As originally developed, the list of model turbines incorporates the fuels used, the typical hours of operation for a unit, the industry sector that may use a turbine, the presence of a duct burner, and information about space limitations. For the base case analysis, the CTWG simplified the model turbines selected. The base case assumes that each turbine is operated for 8,000 hours annually and operates at 80% rated load or greater.

The CTWG also limited the base case analysis to natural gas-fired model turbines. Natural gas is the predominant fuel used by combustion turbines in the ICCR database. 54.3% of the turbines in ICCR Inventory Database Version 3 were reported as firing natural gas exclusively. In addition, 14.5% were reported as being dual fuel units, and it is expected that these units primarily use natural gas. The CTWG has assembled quantitative information available on baseline emissions, catalyst costs and catalyst performance for natural gas-fired turbines. In addition, the CTWG decided to focus the quantitative analysis on natural gas-fired turbines because fuels other than natural gas introduce complicating factors. For example, a catalyst vendor indicated that for turbines that operate continuously on fuel oil, it is preferable to use a special catalyst formulation that is unaffected by sulfur exposure (Chen et al., 1993). The CTWG has no data on the specially formulated catalysts.

In addition, the CTWG limited the base case quantitative analysis to uncomplicated retrofit installations. Although the CTWG identified a number of situations that would complicate a retrofit installation of an oxidation catalyst, especially complications due to space limitations, time did not permit the CTWG to develop quantitative estimates for these complications. Therefore, the base case includes only a qualitative description of retrofit complications, and no costs for retrofit complications are included in the cost-effectiveness values. Based on the experience of the CTWG members, most retrofit installations for existing turbines would involve some complicating factors and, therefore, the costs to retrofit the units with oxidation catalysts would be higher in general, and in some cases much higher, than the costs presented in this base case analysis.

III. BASELINE HAP EMISSIONS FROM COMBUSTION TURBINES

The CTWG used emissions data included in the ICCR Emissions Database to identify HAPs emitted by natural gas-fired combustion turbines and to estimate baseline emission rates. Only emissions tests that met the criteria established by the CTWG for this analysis were considered. Mass emissions for each HAP were calculated using emission factors (lb/MMBtu) from those emission tests that met the CTWG's criteria. Since the rate of emissions reported for natural gas-fired combustion turbines varies, the CTWG used two emission factors to estimate baseline emissions -- the highest emission factor and the average emission factor.

Further discussion of the baseline emissions data used in this analysis and complicating factors is provided below.

A. Source of Baseline HAP Emissions Data

The information available to the CTWG about the emissions of HAPs from combustion turbines is included in the ICCR Emissions Database. The CTWG believes that the emissions database adequately represents the turbine population, and that these source test data are a sufficient basis for emission factors for a cost-effectiveness analysis.

The current version of the emissions database includes over 70 source tests collected by EPA, many of which involve replicate sampling and analysis runs. For each test report EPA has calculated consistent emission factors for measured HAPs based on the emissions concentration reported. A description of the development of the emissions database, including assumptions used in the calculations, is provided as **Appendix B**. Also, EPA and the CTWG have performed a quality assurance review of each test report and determined which reports should be considered adequate for general assessment of HAP emissions from combustion turbines. These review criteria are included in **Appendix C**. When possible, pertinent information identified as missing from test reports was obtained by contacting the tested facilities. Only those source test data considered appropriate for use in evaluating HAP emissions were used to calculate emission factors.

B. Criteria to Include Emission Test Data in Baseline Emissions

The CTWG identified a subset of combustion turbine emission tests from the ICCR Emissions Database to develop the baseline emission factors for this cost-effectiveness analysis, based on the following criteria:

1. Because the baseline emissions estimate is to be done only for natural gas, emission factors were included only from tests of combustion turbines firing natural gas. [42 of the 70 test reports in the database are for natural gas.]

2. Only test reports that were judged to be complete and to have met quality assurance criteria were included. [Of the 42 tests for natural gas, 8 reports were not complete or did not meet QA\QC criteria.]

3. Because combustion turbines typically operate near full load, emission factors were extracted only for combustion turbine tests that were conducted at above 80% of rated load. [Of the 42 tests for natural gas, 11 reports were conducted at less than 80% rated load.]

A list of the tests excluded based on the above criteria is provided in **Appendix D**.

C. Emission Factors for Baseline HAP Emissions

For those test reports in the ICCR Emissions Database that met the criteria discussed above, emission factors were included in this cost-effectiveness analysis for those HAPs measured at concentrations above the test method's detection limit in at least one run. Therefore, none of the emission factors are based solely on non-detects. This criterion is consistent with the ICCR Testing and Monitoring Work Group's recommendations that regulatory decisions should not be based solely on non-detects (ICCR Testing and Monitoring Work Group, 1997).

For natural gas-fired turbines, nine HAPs were measured above the detection limits in at least one run. Both the highest emission factor and the average emission factor were used for the base case analysis. The emission factors are presented in **Table 1**. Baseline annual emissions for each model turbine were calculated using these emission factors. The heat input was calculated by converting the model turbine rating (MW) to MMBtu/hr and dividing by the turbine efficiency, assumed to be 35%. The baseline annual emissions were then calculated using the heat input (MMBtu/hr), the emission factor (lb/MMBtu), and the annual operating hours (hr/yr). The baseline emissions (megagrams/year) for each model turbine are presented in **Table 2**. [Note: The emission estimates used in this analysis are presented as emissions at the stack outlet. The emissions estimates do not address ambient air dispersion of the pollutants, nor ground-level concentrations.]

Table 1. HAPs Emission Factors for the Base Case Analysis

Pollutant	Highest Emission Factor		Average Emission Factor	
	Test	(lb/MMBtu)	(lb/MMBtu)	No. of Tests
Formaldehyde	Test 316.1.1	5.61E-03	7.13E-04	22 Tests
Toluene	Test 28	7.60E-04	1.42E-04	7 Tests
Acetaldehyde	Test 11	3.50E-04	9.12E-05	7 Tests
Xylenes	Test 18	1.20E-04	4.59E-05	5 Tests
Ethylbenzene	Test 18	4.10E-05	4.10E-05	1 Test
Benzene	Test 315.1	3.91E-05	1.03E-05	11 Tests
PAHs	Test 7	7.32E-06	2.23E-06	4 Tests
Acrolein	Test 18	6.08E-06	5.49E-06	2 Tests
Naphthalene	Test 7	3.31E-06	1.46E-06	3 Tests

Source: ICCR Emissions Database for Combustion Turbines

Table 2. Baseline Emissions (Mg/yr) for Each Model Turbine

Baseline Emissions (Mg/yr)-- Highest Emission Factor											
Model Turbine		Formaldehyde	Toluene	Acetaldehyde	Xylenes	Ethylbenzene	Benzene	PAHs	Acrolein	Naphthalene	Total HAPs
2	170 MW	33.810	4.580	2.109	0.723	0.247	0.236	0.044	0.037	0.020	41.806
1	85.4 MW	16.984	2.301	1.060	0.363	0.124	0.118	0.022	0.018	0.010	21.001
7	39.6 MW	7.876	1.067	0.491	0.168	0.058	0.055	0.010	0.009	0.005	9.738
9	27 MW	5.370	0.727	0.335	0.115	0.039	0.037	0.007	0.006	0.003	6.640
15	9 MW	1.790	0.242	0.112	0.038	0.013	0.012	0.002	0.002	0.001	2.213
13	3.5 MW	0.696	0.094	0.043	0.015	0.005	0.005	0.001	0.001	< 0.001	0.861
17	1.13 MW	0.225	0.030	0.014	0.005	0.002	0.002	< 0.001	< 0.001	< 0.001	0.278
Baseline Emissions (Mg/yr) -- Average Emission Factor											
Model Turbine		Formaldehyde	Toluene	Acetaldehyde	Xylenes	Ethylbenzene	Benzene	PAHs	Acrolein	Naphthalene	Total HAPs
2	170 MW	4.297	0.856	0.550	0.277	0.247	0.062	0.013	0.033	0.009	6.344
1	85.4 MW	2.159	0.430	0.276	0.139	0.124	0.031	0.007	0.017	0.004	3.187
7	39.6 MW	1.001	0.199	0.128	0.064	0.058	0.014	0.003	0.008	0.002	1.478
9	27 MW	0.682	0.136	0.087	0.044	0.039	0.010	0.002	0.005	0.001	1.008
15	9 MW	0.227	0.045	0.029	0.015	0.013	0.003	0.001	0.002	< 0.001	0.336
13	3.5 MW	0.088	0.018	0.011	0.006	0.005	0.001	< 0.001	0.001	< 0.001	0.131
17	1.13 MW	0.029	0.006	0.004	0.002	0.002	< 0.001	< 0.001	< 0.001	< 0.001	0.042

D. Complicating Factors

The emission factors used for the base case cost-effectiveness analysis, as presented in **Table 1**, represent a necessary simplification of actual HAP emissions which could be expected in the existing population of combustion turbines in the United States. The following complicating factors would change the baseline emissions of certain combustion turbines in some cases:

1. The use of the highest HAP emission factors reported tends to overestimate HAP baseline emissions.

2. For the "highest" case, the highest HAP emissions factors for each pollutant were used. It has not been shown that all these "highs" would occur simultaneously from a combustion turbine. In fact, it is not likely that all the "highs" for all pollutants would occur simultaneously. Therefore, total HAP emissions are overstated in the case where the highest emission factor from all the tests is used for each HAP.

3. HAP emissions may be different for combustion turbines using fuels other than natural gas.

4. HAP emission factors used in this base case analysis tend to overestimate HAP emissions for uncontrolled turbines, since a significant portion of the emissions tests in the ICCR Emissions Database for natural gas-fired turbines were conducted on units that use steam or water injection to reduce NOx emissions, and steam or water injection may result in increased HAP emissions due to the cooling of the combustion process.

5. For some pollutants there are very few emissions test reports available. In those cases where emission averages rely on very few tests, it is unclear whether the resulting emission factor is representative of the turbine population.

6. The baseline emissions included in this analysis may underestimate annual HAP emissions from turbines that operate at less than 80% load, since the emission factors included in this base case analysis do not include the higher emission rates that may occur when turbines are operated at low loads.

IV. OXIDATION CATALYST COSTS

The CTWG obtained information on the costs of acquiring, installing, and operating oxidation catalysts for HAPs reduction on combustion turbines from the following sources:

- Quotes provided to EPA by catalyst vendors
- Costs gathered by the Gas Research Institute (GRI)
- Estimates provided by Work Group members

The methodology to estimate the total annual costs for oxidation catalysts was obtained from the EPA "OAQPS Control Cost Manual" (EPA, 1990). The OAQPS methodology provides generic cost categories and default assumptions to estimate the installed costs of control devices. The CTWG relied on the OAQPS methodology to develop the cost-effectiveness analysis because the Work Group understands that this is the methodology that EPA has used in the past to assess cost-effectiveness. The GRI study (Ferry et al., 1998) also relied on the OAQPS methodology.

The OAQPS cost manual requires direct cost inputs for certain key elements, such as control device capital costs, and then relies on default assumptions (percentages of the direct cost inputs) to estimate other costs, such as installation. The following sections describe the direct cost inputs into the OAQPS methodology and the costs estimated using the OAQPS default assumptions. A printout of the spreadsheet used to estimate costs is presented as **Appendix E**.

The OAQPS manual uses five cost categories to describe the annual incremental cost incurred by installing a control device, such as an oxidation catalyst:

- **Purchased Equipment Costs (PEC)** include the capital cost of the catalyst and auxiliary equipment, and the cost of instrumentation, sales tax, and freight.

- **Direct Costs for Installation (DCI)** are the construction-related costs associated with installing the catalyst.

- **Indirect Costs for Installation (ICI)** include expenses related to engineering and start up**.**

- **Direct Annual Costs (DAC)** include catalyst replacement and disposal costs and the annual increases in utilities and operating and maintenance costs.

- **Indirect Annual Costs (IAC)** are the annualized cost of the catalyst system and costs due to tax, overhead, insurance and administrative burdens.

The cost used in the cost-effectiveness calculation is the total annual cost, which is the sum of the DAC and IAC.

A. Cost Inputs

The CTWG developed cost estimates for the following inputs:

- Capital cost of the oxidation catalysts
- Capital cost of the catalyst housing
- Contingency for capital costs
- Catalyst life and equipment life
- Catalyst disposal costs
- Interest rate for capital recovery
- Direct annual operating & maintenance costs
- Fuel penalty costs
- Annual compliance test costs

A description of the each cost input is provided below.

Capital cost of the oxidation catalysts

The CTWG used cost estimates from Engelhard, a catalyst vendor, for six turbine exhaust flows ranging from 28.4 lb/sec to 984.0 lb/sec to estimate the capital cost of the oxidation catalysts. The Engelhard costs were based on an oxidation catalyst that would achieve

90% CO conversion efficiency and 1” pressure drop across the catalyst panels (not total system pressure drop) and include the cost of an internal support frame and catalyst modules. Regression analysis on these cost data provided by the vendor suggested that there is a nearly linear relationship between catalyst cost and exhaust flow rate ($r^2 = 0.993$, when Catalyst cost=1541.8*(lb/sec)+102370). In estimating catalyst costs for the seven model turbines, the CTWG relied on the equation based on the Engelhard cost quotes, where cost is a function of turbine exhaust flow. Additional cost information reviewed by the CTWG is discussed in complicating factors.

Capital cost of the catalyst housing

The capital cost of the catalyst housing was estimated as 30% of the total cost of the catalyst system (the catalyst plus housing). This estimate is based on estimates provided orally by catalyst vendors. The CTWG contacted catalyst installers to get additional information on the costs for catalyst housings, but the data was not made available in time to include it in the base case analysis.

Contingency

A contingency of 10% of the sum of the purchased equipment costs, direct costs of installation, and indirect costs of installation was incorporated in the base case analysis. The budgeted contingency would cover costs associated with equipment redesign and modifications, cost escalations, and delays in start-up. The OAQPS Control Cost Manual recommends a 3% contingency. However, the CTWG agreed that a contingency of at least 10 percent would be appropriate for the base case analysis since the analysis is based on a preliminary vendor quote, not a guaranteed quote. Based on CTWG experience, a contingency factor of 25 percent DCI and ICI (direct and indirect installation costs) is budgeted in the early planning stages of a project and a contingency factor of at least 10 percent is budgeted once the project is under contract.

Catalyst life and equipment life

For the base case, the lifetime of purchased equipment was assumed to be fifteen years, except for the catalyst. Two scenarios were used for the catalyst life: the vendor guaranteed life (three years) and the “typical” life (six years) reported by catalyst vendors and users. The guaranteed life of the catalyst was used by EPA in the cost-effectiveness analysis for a passive catalytic device (non-selective catalytic reduction, NSCR) in the Alternative Control Techniques (ACT) document for reciprocating internal combustion engines (EPA, 1993b). In the Turbine ACT document, EPA used 5 years as the catalyst life for Selective Catalytic Reduction (SCR) (EPA, 1993a). The Turbine ACT did not specify whether the catalyst life was guaranteed life or "typical" life for SCR. However, in general, EPA prefers to rely on the useful life of equipment for cost-effectiveness calculations. The CTWG determined that the base case should evaluate the costs using both the guaranteed life and the typical life to account for the uncertainty regarding the long-term performance of oxidation catalysts. Further discussion of the issues related to catalyst life are discussed as complicating factors.

The cost of catalyst replacement is annualized by applying a capital recovery factor based on the catalyst lifetime and interest rate to the cost of the oxidation catalyst only (based on the Engelhard formula).

Catalyst Disposal Costs

For the base case analysis, costs for catalyst disposal were limited to the freight charge associated with shipping the spent modules back to the vendor. Based on the experience of CTWG members, catalyst vendors do not charge for catalyst disposal since the vendors can recover the noble metals from the spent catalysts.

Interest Rate for Capital Recovery

An interest rate of 7 percent was used in the base case to calculate capital recovery. The EPA Co-Chair of the ICCR Economics Work Group recommended this interest rate for the cost-effectiveness analysis.

Direct annual operating and maintenance costs

Operating labor costs were estimated using a factor of $25 per hour operating labor and an estimate of two hours per day incremental labor. The labor costs cover costs for operator duties likely to result from installing an oxidation catalyst and complying with MACT. Those duties include 1) inspection of the continuous parameter monitoring device, 2) collection and review of continuous parameter monitoring data, 3) inspection of the control device, and 4) recordkeeping and reporting assumed to be required by the MACT standard. In developing the labor estimates, the CTWG reviewed the EPA estimates for labor for NSCR for reciprocating internal combustion engines and for SCR for turbines included in the Alternative Control Techniques (ACT) documents (EPA, 1993a and 1993b). The CTWG agreed that the labor estimates for NSCR would more closely approximate the labor associated with an oxidation catalyst, since NSCR is essentially a passive catalytic device, like oxidation catalysts. The CTWG agreed that labor costs for SCR for turbines would be greater than the labor costs for oxidation catalysts, since SCR may require frequent inspection and adjustment of the ammonia feed system. Maintenance costs, including labor and materials, were estimated as 10% of the total purchased equipment cost, based on the ACT formula for NSCR. Maintenance costs cover catalyst washing (with water), maintenance of monitoring equipment, and labor for catalyst replacement (including removal and return of old catalyst and installation of replacement).

Fuel penalty costs

Increased pressure drop in the exhaust of a gas turbine will impact both heat rate and power output. For the base case analysis, fuel penalty costs are included to compensate for the increased heat rate as a result of the increased exhaust backpressure on the turbine that results from installing an oxidation catalyst. The fuel penalty is assessed as the cost of increased fuel, which is calculated by assuming a heat rate increase of 0.105% per inch of pressure drop (measured in inches of water column) and estimates of $2 per MMBtu and a 9,000 Btu/hp-hr baseline. The heat rate increase of 0.105% was drawn from the GRI study. The CTWG agreed that 0.105% is a very low estimate of the heat rate increase anticipated and most turbines would have higher increased heat rate due to backpressure from the catalyst. Other estimates of the heat rate increase are discussed in the complicating factors portion of this section. The estimate of $2 per MMBtu for natural gas was drawn from the GRI study. The CTWG agreed that this estimate is low compared to market value of natural gas at this time. The estimate of increased exhaust backpressure on the turbine from the catalyst was based on an assumption that the total pressure drop associated with the catalyst system is solely the pressure drop across the catalyst panels. The CTWG agreed that the total pressure drop would be higher than the pressure drop across the catalyst panels due to the pressure drop associated with the inlet and outlet ductwork for the catalyst system. Therefore, the increase in the exhaust backpressure and, therefore, the fuel penalty costs resulting from the increase in exhaust backpressure are understated in the base case analysis.

The Turbine World Handbook indicates that exhaust backpressure may result in a loss of power. The costs for loss of power were not included in the base case quantitative analysis. These costs would increase the cost of control beyond the base case costs presented in this paper. The costs for loss of power are discussed in the complicating factors portion of this section.

Annual Compliance Test Costs

Costs to perform one annual emissions compliance test are included in the base case. The costs for this annual test are estimated at $5,000. The costs were estimated based on an assumption that no continuous emissions monitoring data would be required in a MACT standard for combustion turbines. Instead, it was assumed that the MACT would require continuous monitoring for an operating parameter, such as temperature at the catalyst, along with an annual emissions test. The costs also were based on an assumption that a surrogate criteria pollutant can be measured and that HAPs would not be speciated.

B. Costs Estimated by OAQPS Control Cost Manual

The methodology outlined in the OAQPS Control Cost manual was used by the CTWG to estimate costs for the following:

- Capital cost for instrumentation (continuous parameter monitor)
- Sales tax for equipment purchases
- Freight for equipment purchases
- Direct installation costs (DCI), including foundations & supports, handling & erection, electrical, piping, insulation for ductwork, and painting.
- Indirect installation costs (ICI), including engineering, construction and field expenses, contractor fees, start-up, and performance tests.
- Indirect annual costs (IAC), including annualized equipment costs, overhead, administrative costs, property taxes, and insurance.

A description of the methodology to estimate these costs is provided below.

Costs for instrumentation, taxes and freight are estimated by applying factors from the OAQPS cost manual to the capital cost of the catalyst and auxiliary equipment. These costs (catalyst capital cost, instrumentation, taxes, and freight) are then summed to estimate the total Purchased Equipment Costs (PEC). The components of the DCI (foundations and supports, erection and handling, electrical work, piping, painting and insulation) are then calculated by applying OAQPS cost manual factors to the PEC. Likewise, the components of the ICI (engineering, construction and field expenses, contractor fees, start-up, and initial performance test) are also calculated by applying factors to the PEC.

Indirect Annual Costs (IAC) are the annualized cost of the catalyst housing and the costs for overhead, administrative tasks, property taxes, and insurance. The equipment costs are annualized by applying a capital recovery factor (based on the equipment life, 15 years, and interest rate) to the sum of the direct and the indirect equipment costs, excluding the cost of the catalyst modules. The cost of the catalyst modules is considered a direct annual cost (DAC), and is annualized separately. Factors applied to the sum of the direct and indirect equipment costs (including contingency) are used to estimate the overhead, administrative costs, property taxes, and insurance.

C. Summary of Base Case Cost Estimates

Table 3 presents the range of costs estimated for the seven model turbines included in the base case cost-effectiveness analysis. The costs for each model turbine are presented in **Appendix E**. The highest annual costs are for the largest model turbine and the lowest annual costs are for the smallest model. The $/MW are lower for the larger model turbines and higher for the smaller model turbines.

Table 3. Range of Costs Estimated for Seven Model Turbines

Cost Category	Costs for 3-Year Catalyst Life*		Costs for 6-Year Catalyst Life*	
Total Capital Cost	$360,000 -	$4,800,000	$360,000 -	$4,800,000
Direct Annual Cost	$96,000 -	$980,000	$74,000 -	$680,000
Indirect Annual Cost	$65,000 -	$700,000	$65,000 -	$700,000
Total Annual Costs (DAC + IAC)	$160,000 -	$1,700,000	$140,000 -	$1,400,000

*Costs are rounded.

D. Complicating Factors

This section presents the views of the CTWG with regard to factors that complicate the estimation of the costs of acquisition, installation, and operation of oxidation catalyst on combustion turbines. For discussion, these complicating factors are divided into five categories:

- factors related to the cost of acquiring the oxidation catalyst,
- costs associated with site installation complications,

- costs associated with performance testing,
- complicating factors associated with increased exhaust backpressure, and
- costs associated with compliance monitoring.

Factors Complicating the Estimation of Catalyst Acquisition Costs

The catalyst costs used in this base case analysis are based on a formula that was derived from one vendor's cost quotes for six different sizes of combustion turbines. The vendor's cost quotes covered a range of turbine sizes that is similar to the turbine sizes represented in the seven model turbines used in this cost-effectiveness analysis. Exhaust flow rates for the vendor's cost quotes ranged from 28.4 lb/sec to 984 lb/sec, while exhaust flow rates for the seven model turbines ranged from 14.2 lb/sec to 986 lb/sec. The formula developed by the CTWG for this cost-effectiveness analysis represents a necessary simplification of the vendor's cost quotes to facilitate estimating costs for the seven model turbines used in this analysis.

The CTWG had cost estimates for oxidation catalysts available from two other sources: 1) cost estimates provided by Mr. Marvin Schorr of General Electric (Schorr, 1998), and 2) cost estimates included in the GRI cost study (Ferry et al., 1998). Cost estimates were provided by General Electric for two large turbines (exhaust flow rates of 400 lb/sec and 1200 lb/sec). The formula calculated using the General Electric cost estimates is (0.85*(568.75*Exhaust Flow Rate (lb/hr) +172,500). For small turbines, the costs estimated using the General Electric formula are higher than the costs used in this base case analysis. For example, the General Electric formula estimates $153,490 for the catalyst for a 1.13 MW turbine, while the costs used in this base case analysis are $105,624. For a 3.5 MW turbine, the costs are similar, $166,446 estimated using the General Electric formula and $165,584 used in this analysis. For larger turbines, the costs estimated using the General Electric formula are lower than the costs used in this base case analysis. The differences in the costs estimated using the two different approaches increase with turbine size. For the 170 MW turbine, the General Electric formula estimates the cost of the catalyst as $623,294, while $1,622,585 was used in this cost-effectiveness analysis. [Note: the quote provided by Engelhard for a 170 MW turbine, exhaust flow 984.0lb/sec was $1,550,000.] The CTWG agreed not to use the General Electric cost estimates for this base case analysis for the following reasons: 1) cost estimates were provided only for two large turbines, and 2) the costs seemed to underestimate the costs when compared with the quotes received directly from a catalyst vendor.

The CTWG also reviewed the cost estimates included in the GRI study. In that case, GRI used cost quotes provided by two catalyst vendors for a 6,000 horsepower turbine. Vendors provided cost quotes for a range of VOC control estimates: 95 percent, 50 percent, 35 percent, and 22 percent. In comparing the cost quote in the GRI study for 95 percent VOC control and 98 percent CO control, the CTWG noted that the costs were similar to the costs for a 6,000 hp turbine estimated using the formula in this base case (assuming 90 percent CO control) -- $204,500 in the GRI study, and $206,796 using the base case formula. The CTWG decided not to use the GRI costs for this analysis because there was insufficient information to develop a reliable cost formula that could be applied to a wide range of turbine models, ranging in size from 1.13 MW to 170 MW.

The CTWG notes that vendor quotes that have been obtained are essentially for CO oxidation catalysts. As noted above, available emissions data indicates that CO/VOC oxidation catalysts should reduce organic HAP compounds. However, the CTWG is not aware of any actual industry experience in the acquisition of an oxidation catalyst specified to achieve a percentage reduction of formaldehyde, or the other HAPs. In the absence of such experience, the cost estimate for an oxidation catalyst designed to reduce organic HAPs from combustion turbines is uncertain. Uncertainty about the estimated cost for a HAP reduction catalyst is increased when considering that oxidation catalysts would be required for fuels other than natural gas. Oxidation catalysts for oil fired turbines may have to be formulated differently than for gas fired turbines, and may have different lifetime and degradation characteristics.

Another key uncertainty in estimating oxidation catalysts costs is the assumption regarding catalyst life. Clearly, a catalyst that can be relied upon to function for many years will have lower annual costs than a catalyst that must be replaced more often. The issue of catalyst lifetime includes estimating the probability of complete failure of the catalyst, and also estimating the degradation of catalyst performance over time.

The CTWG notes that there may be a difference between the expected useful life of an oxidation catalyst, and the period of the vendor's performance guarantee. This raises the question of which period should be used in calculating cost-effectiveness. As noted in another section, the CTWG has elected to present a number of cost-effectiveness estimates based on different assumptions about catalyst life and performance.

Limited information was available to the CTWG on the life of the catalyst. Information from an emissions test conducted by GRI on a ten-year-old CO oxidation catalyst indicates that performance can degrade when the catalyst is used for an extended period of time (10 years in that case). The GRI test is described under **Section V** of this paper. Further information is not available that would allow the CTWG to estimate the expected rate of oxidation catalyst performance degradation, or the effect of maintenance (such as catalyst washing) on catalyst life. According to catalyst vendors, the degradation of catalyst performance over time is not linear. The CTWG has not obtained any information that would allow the Work Group to estimate the expected rate of performance degradation over the life of the catalyst.

Costs associated with site installation complications

Costs for retrofit complications were not available for the base case analysis. Site-specific factors can have a major impact on the cost of retrofitting a catalyst control system to an existing turbine installation. In general, the heat recovery unit (if one exists) must be altered, ductwork and piling supports must be added, and piping, electrical conduits and wiring must be lengthened. Some turbine installations have enough space between the turbine exhaust and the heat recovery unit to add the catalyst system. In cases where space is very limited, the heat recovery unit might have to be removed and replaced with a new vertical style unit. One of the Work Group members provided retrofit costs for adding a catalyst system to an ABB Type 11 gas turbine (gas flow = 580 lb/sec) (Allen, 1998a and 1998b). The retrofit costs totaled about $800,000, including $100,000 for ductwork. The cost of down time is also site specific. In the case described above, the cost cited by the Work Group member for down time was about $3.5 million based on a 35 day outage, a power sales price of $35/MWh, and a steam cost $4.5/thousand pounds of steam (Allen, 1998a).

Costs Associated with Performance Testing

Costs for performance testing were included in the base case quantitative analysis in accordance with the OAQPS Control Cost Manual. The costs for performance testing are estimated as 0.01% of the Purchased Equipment Costs (PEC). For the 170 MW turbine, $27,000 was calculated as the performance test costs using the OAQPS formula. For the 1.13 MW turbine, $2,095 was calculated as the performance test costs using the OAQPS formula. The CTWG agreed that the costs for stack emissions testing would be fixed, regardless of turbine size. The costs estimated for performance testing may have been underestimated for the base case analysis, especially for the small model turbines.

Complicating Factors Associated with Increased Exhaust Backpressure

For the base case quantitative analysis, fuel penalty costs were estimated assuming a 0.105% heat rate increase per inch of pressure resulting from installation of a catalyst system. The CTWG agreed that 0.105% is a very low estimate of the heat rate increase.

The Gas Turbine World 1997 Handbook provides rough rule of thumb estimates of heat rate increase and power loss per inch pressure drop (Gas Turbine World 1997). For aeroderivative turbines, the Handbook indicates that every 4 inches outlet loss will increase heat rate 0.7% (0.175% per inch) and reduce power output 0.7%. For heavy frame turbines, the Handbook indicates that every 4 inches outlet loss will increase heat rate 0.6% (0.15% per inch) and reduce power output 0.6%. Therefore, the heat rate increase due to increased pressure drop is understated in the base case analysis.

To estimate pressure drop for the base case quantitative analysis, it was assumed that the total pressure drop associated with the catalyst system is solely the pressure drop across the panels. The CTWG agreed that the total pressure drop would be higher than the pressure drop across the catalyst panels alone due to the inlet and outlet ductwork. Therefore, the operating costs associated with the increase in exhaust backpressure are understated in the base case analysis. The fuel penalty costs associated with backpressure may be significantly higher when a more realistic estimate of the catalyst system pressure drop is used.

In addition, implementing oxidation catalyst control may result in a reduction in turbine power output caused by increased exhaust backpressure on the engine. The costs associated with the power loss depend on site-specific factors (e.g., value of lost product or capital and annual costs for equipment required to make up for the power loss). The increase in exhaust backpressure results in a loss of power sales if the unit is operating at full load. One of the Work Group members provided information on the loss in annual sales at different selling prices for electrical power (Allen, 1998b). For a GE Frame 7 turbine, the annual cost (i.e., lost sales) per inch of water pressure drop may be estimated using the following equation:

Annual Cost ($/inch) = 1,160 * Power Value ($/MWh) + 100

For this example turbine unit, if electricity can be sold for $40 per MWh, the annual cost per each additional inch of water pressure drop caused by the catalyst would equal $46,500.

These costs were not incorporated into the base case analysis. The cost associated with power loss would increase the costs for the control system.

Costs Associated with Compliance Monitoring

If the MACT would require speciated HAP emissions test data, the costs for the annual compliance test would increase significantly. Also, if compliance tests must be conducted more frequently than annually, the costs would increase.

V. PERFORMANCE OF OXIDATION CATALYSTS IN REDUCING HAP EMISSIONS

Oxidation catalysts have been installed on combustion turbines for the purposes of controlling emissions of carbon monoxide (CO) and some volatile organic compounds (VOC). The catalyst is designed to promote the oxidation of hydrocarbon compounds to carbon dioxide (CO_2) and water (H_2O). It is expected that existing catalysts similar to those in use for CO and VOC control may oxidize organic HAPs.

In order to estimate the quantitative performance of an oxidation catalyst the CTWG evaluated two emissions test reports and reviewed engineering estimates of potential oxidation catalyst performance.

A. HAP Emissions Test Data for Oxidation Catalysts

At present, no HAP emissions tests in the ICCR Emissions Database include before and after testing of a combustion turbine with an oxidation catalyst. Emissions test data on the performance of oxidation catalysts should be collected during the CTWG testing campaign.

The CTWG identified two existing emission test reports that provide some information on the performance of oxidation catalysts in reducing HAP emissions. The two emission tests are still being evaluated and may be included in the database after review. One test was conducted by the Gas Research Institute(GRI), in cooperation with the American Petroleum Institute (API) and Southern California Gas (SoCal), in March 1998, on a combustion turbine using a passive oxidation catalyst system, similar to the catalyst used for this base case cost-effectiveness evaluation. A summary of this test has been provided to the CTWG and the complete test data will be provided to EPA when it is available (Gundappa, 1998). The complete test report will be required by EPA and the report will have to undergo review prior to being included in the ICCR Emissions Database. The oxidation catalyst installed on this turbine is a precious metal catalyst, similar to the catalyst technology used as the basis for this cost-effectiveness analysis. This type of oxidation catalyst may be used over a temperature range of 450 F to 1500 F (Chen et al., 1993).

The second test was submitted to EPA for a new catalytic oxidation control system, called SCONOx™ (Bell and Finken, 1997). Although the SCONOx™ system relies on oxidation to reduce hydrocarbons, such as CO, or HAPs, such as formaldehyde, the SCONOx™ catalyst is a more complicated control system than the oxidation catalyst used for this base case cost-effectiveness evaluation. SCONOx™ may be operated over a temperature range of 300 F to 700 F (Goal Line Environmental Technologies, LLC). The cost and cost-effectiveness values presented in this paper were not based on costs for the SCONOx™ system. However, the CTWG included a discussion of the source test results as an indicator of the types of emission reductions that may be achievable for systems that rely on oxidation to reduce HAP emissions. A description of the SCONOx™ system is provided in **Appendix F**. The results from these two emissions tests are discussed below.

GRI/API/SoCal Test

The GRI/API/SoCal testing was conducted in March 1998. GRI, API, and SoCal added the emissions test to an existing emissions testing program in order to provide data to the CTWG on the performance of oxidation catalysts. Some members of the CTWG and EPA representatives witnessed the GRI/API/SoCal test. The test was performed on a 20 MW GE LM2500 turbine equipped with a Johnson Matthey CO oxidation catalyst. Three load conditions were tested, including full load (typical) and part loads (88% and 70% of rated load). Concentrations of HAPs, including formaldehyde, were measured before and after the oxidation catalyst. HAP and CO measurements were conducted with Fourier transform infrared (FTIR) sampling upstream and downstream of the oxidation catalyst. Aldehydes also were measured with the California Air Resources Board (CARB) Method 430, which relies on an aqueous 2,4-Dinitrophenylhydrazine solution. Complete results of the test were not available in time to incorporate them into the ICCR Emissions Database. However, the CTWG has been provided a summary of the results (Gundappa, 1998). Based on FTIR, formaldehyde emissions upstream of the catalyst were in the approximate range of 400 to 460 parts per billion by volume (ppbv) and CO emissions upstream of the catalyst were in the range of 10 to 17 parts per million by volume (ppmv). Both formaldehyde and CO emissions increased as the load decreased. With FTIR, the reduction in emissions across the oxidation catalyst was on the order of 10 to 30 percent for formaldehyde and 25 to 33 percent for CO, with the highest reduction at the lowest load condition. CARB 430 results did not agree with the FTIR data. In some cases, the CARB 430 results indicated that levels of aldehydes (formaldehyde and acetaldehyde) increased after the catalyst.

SCONOx™ Test

A unit equipped with a SCONOx™ catalyst system was tested on March 14, 1997, by Delta Air Quality Services (Bell and Finken, 1997). Samples were collected at the inlet to the catalyst and at the exhaust from the cogeneration unit (turbine exhaust stack) and analyzed for the following three HAPs: formaldehyde, acetaldehyde, and benzene. Formaldehyde and acetaldehyde reportedly were reduced by 97% and 94%, respectively, based on the catalyst inlet and turbine exhaust concentrations. No conclusion regarding the control efficiency for benzene could be drawn since the levels before and after the catalyst were both very low and within 0.05 parts per billion of each other.

A subgroup of the CTWG reviewed the SCONOx™ report in greater detail to determine if the data from this test should be included in the emissions database. The subgroup was concerned with the accuracy of the catalyst inlet concentrations measured during the test since isokinetic sampling was not conducted nor was a multi-point probe used to collect the samples. However, the catalyst inlet concentrations were consistent with other source tests involving the same model turbine (GE LM 2500), using water injection. Also, even if the catalyst inlet concentrations were one-half to one-third of the average concentration measured during the source test, the efficiency of the SCONOx™ would still exceed 90% for formaldehyde. Therefore, the subgroup decided to support inclusion of the data from this test in the emissions database, with the caveat that EPA may want to retest this unit to address some of the specific concerns identified during the subgroup's review.

Based on a review of the two emissions tests available, the CTWG concluded that organic HAPs, such as formaldehyde and acetaldehyde, may be reduced using after-treatment controls that rely on catalytic oxidation. The Work Group also concluded that, in some cases, a high percent reduction may be possible for certain pollutants. However, the CTWG noted that the limited data available is not sufficient to draw conclusions about the achievability of high emission reductions over the life of catalytic devices. In addition, the CTWG noted that although there is some data that suggests catalysts degrade over time, the rate and the extent of the degradation cannot be determined based on the limited data.

B. Engineering Estimates of HAP Reduction Performance for Oxidation Catalysts

The CTWG reviewed information available in the literature on the HAP reduction performance of oxidation catalysts on organic HAPs, such as formaldehyde. In particular, the Work Group reviewed an article prepared by Engelhard, the catalyst vendor that supplied the cost quotes for this base case cost-effectiveness analysis (Chen et al., 1993). In the article, Engelhard notes that oxidation catalysts for combustion turbines are typically designed to achieve between 80 and 95 percent CO removal. In addition, the article indicates the conversion level for each species of hydrocarbon will depend on its diffusion rate in the exhaust gas. In general, larger, heavier molecules will diffuse more slowly than smaller, lighter molecules. As the size of the hydrocarbon molecule increases, hydrocarbon conversion decreases due to decreased gas diffusivity. According to the article, an oxidation catalyst designed for 90 percent CO removal will achieve 77 percent reduction of formaldehyde, 72 percent reduction of benzene, and 71 percent reduction of toluene. The article notes that the relative conversion rates do not depend on geometry and that reduction for molecules larger than formaldehyde will be lower than rates achievable for formaldehyde.

C. Summary of Base Case Performance Estimate

The CTWG has agreed to use two performance values for the base case cost-effectiveness analysis -- 80 percent emissions reduction and 50 percent emissions reduction. 80 percent emissions reduction is used for both the 3-year and 6-year catalyst life assumptions. 50 percent emissions reduction is evaluated for a 6-year catalyst life.

The CTWG believes these levels of reduction represent appropriate levels of reduction for the base case cost-effectiveness analysis, covering both high and moderate levels of emission reduction. The Work Group relied on the Engelhard engineering estimates for formaldehyde to select 80% reduction as the catalyst performance in the base case analysis (77% rounded up to 80%). Although the Engelhard article indicates that emission reductions for larger molecules, such as PAHs, may be less than the reduction achieved for formaldehyde, the HAP reduction performance for the base case analysis was set to 80 percent for all pollutants. The Work Group selected 50% reduction as a moderate level of emission reduction to examine the sensitivity of the cost-effectiveness to any significant degradation of the catalyst performance that might occur over time. Additional emissions test data before and after oxidation catalysts would be necessary to determine whether the levels of reductions are achievable for combustion turbines, considering the full range of operating conditions and catalyst degradation.

The emission reductions achieved for each model turbine assuming 80 percent reduction and 50 percent reduction are presented in **Tables 4** and **5.**

Table 4. Emissions Reductions for Each Model Turbine Assuming 80% HAPs Reduction Performance

Emissions Reductions (Mg/yr)-- Highest Emission Factor -- 80% HAPs Reduction Performance											
Model Turbine		Formaldehyde	Toluene	Acetaldehyde	Xylenes	Ethylbenzene	Benzene	PAHs	Acrolein	Naphthalene	Total HAPs
2	170 MW	27.048	3.664	1.687	0.579	0.198	0.189	0.035	0.029	0.016	33.445
1	85.4 MW	13.587	1.841	0.848	0.291	0.099	0.095	0.018	0.015	0.008	16.801
7	39.6 MW	6.301	0.854	0.393	0.135	0.046	0.044	0.008	0.007	0.004	7.791
9	27 MW	4.296	0.582	0.268	0.092	0.031	0.030	0.006	0.005	0.003	5.312
15	9 MW	1.432	0.194	0.089	0.031	0.010	0.010	0.002	0.002	0.001	1.771
13	3.5 MW	0.557	0.075	0.035	0.012	0.004	0.004	0.001	0.001	< 0.001	0.689
17	1.13 MW	0.180	0.024	0.011	0.004	0.001	0.001	< 0.001	< 0.001	< 0.001	0.222

Emissions Reductions (Mg/yr)-- Average Emission Factor -- 80% HAPs Reduction Performance											
Model Turbine		Formaldehyde	Toluene	Acetaldehyde	Xylenes	Ethylbenzene	Benzene	PAHs	Acrolein	Naphthalene	Total HAPs
2	170 MW	3.438	0.685	0.440	0.221	0.198	0.050	0.011	0.026	0.007	5.075
1	85.4 MW	1.727	0.344	0.221	0.111	0.099	0.025	0.005	0.013	0.004	2.549
7	39.6 MW	0.801	0.159	0.102	0.052	0.046	0.012	0.003	0.006	0.002	1.182
9	27 MW	0.546	0.109	0.070	0.035	0.031	0.008	0.002	0.004	0.001	0.806
15	9 MW	0.182	0.036	0.023	0.012	0.010	0.003	0.001	0.001	< 0.001	0.269
13	3.5 MW	0.071	0.014	0.009	0.005	0.004	0.001	< 0.001	0.001	< 0.001	0.104
17	1.13 MW	0.023	0.005	0.003	0.001	0.001	< 0.001	< 0.001	< 0.001	< 0.001	0.034

Table 5. Emissions Reductions for Each Model Turbine Assuming 50% HAPs Reduction Performance

Emissions Reductions (Mg/yr)-- Highest Emission Factor -- 50% Reduction Performance											
Model Turbine		Formaldehyde	Toluene	Acetaldehyde	Xylenes	Ethylbenzene	Benzene	PAHs	Acrolein	Naphthalene	Total HAPs
2	170 MW	16.905	2.290	1.055	0.362	0.124	0.118	0.022	0.018	0.010	20.903
1	85.4 MW	8.492	1.150	0.530	0.182	0.062	0.059	0.011	0.009	0.005	10.501
7	39.6 MW	3.938	0.533	0.246	0.084	0.029	0.027	0.005	0.004	0.002	4.869
9	27 MW	2.685	0.364	0.168	0.057	0.020	0.019	0.004	0.003	0.002	3.320
15	9 MW	0.895	0.121	0.056	0.019	0.007	0.006	0.001	0.001	0.001	1.107
13	3.5 MW	0.348	0.047	0.022	0.007	0.003	0.002	< 0.001	< 0.001	< 0.001	0.430
17	1.13 MW	0.112	0.015	0.007	0.002	0.001	0.001	< 0.001	< 0.001	< 0.001	0.139
Emissions Reductions (Mg/yr)-- Average Emission Factor -- 50% HAPs Reduction Performance											
Model Turbine		Formaldehyde	Toluene	Acetaldehyde	Xylenes	Ethylbenzene	Benzene	PAHs	Acrolein	Naphthalene	Total HAPs
2	170 MW	2.149	0.428	0.275	0.138	0.124	0.031	0.007	0.017	0.004	3.172
1	85.4 MW	1.079	0.215	0.138	0.069	0.062	0.016	0.003	0.008	0.002	1.593
7	39.6 MW	0.500	0.100	0.064	0.032	0.029	0.007	0.002	0.004	0.001	0.739
9	27 MW	0.341	0.068	0.044	0.022	0.020	0.005	0.001	0.003	0.001	0.504
15	9 MW	0.114	0.023	0.015	0.007	0.007	0.002	< 0.001	0.001	< 0.001	0.168
13	3.5 MW	0.044	0.009	0.006	0.003	0.003	0.001	< 0.001	< 0.001	< 0.001	0.065
17	1.13 MW	0.014	0.003	0.002	0.001	0.001	< 0.001	< 0.001	< 0.001	< 0.001	0.021

D. **Complicating Factors**

This section presents the views of the CTWG with regard to factors that complicate the estimation of the performance of oxidation catalysts in the reduction of organic HAP in the exhaust of combustion turbines.

Uncertainty About the Real World Performance of Oxidation Catalysts for HAPs

As noted earlier in this paper, although there are oxidation catalysts installed on existing turbines for control of CO and some VOCs, there are not conclusive emissions data available regarding the HAP reduction performance of those oxidation catalysts over time. CO catalysts systems in use operate on far higher levels of CO than the expected concentration of HAPs. The cost-effectiveness estimates used for this base case analysis are derived from engineering judgement rather than actual data. It is possible that it may be more difficult than anticipated to achieve a consistent 80% reduction of HAPs across a real world population of combustion turbines running under various ambient conditions and operating points.

Differential Performance for Various HAPs

The assumption used in this base case analysis that oxidation catalysts will have the same HAP reduction performance for all organic HAPs was necessary because there was insufficient emissions data to estimate HAP reduction performance for specific species of HAPs. The CTWG is aware that this assumption is incorrect, based on engineering estimates performed by Engelhard, a catalyst vendor (Chen et al., 1993). Engelhard indicates that individual HAPs will be oxidized at different rates due to differences in the size of the hydrocarbons and that the HAP reduction performance for each HAP will depend on its diffusion rate. In general, larger, heavier molecules (like PAHs) will diffuse more slowly than smaller, lighter molecules (like CO).

The CTWG notes that the assumptions used in this base case analysis tend to overestimate HAP reduction efficiencies for HAPs other than formaldehyde, especially HAPs like PAHs that are larger, heavier molecules.

Decreased Catalyst Performance Over Time

This effect was discussed as a part of the evaluation of catalyst life for costing purposes. A decline in catalytic activity also would impact the performance side of the equation in that fewer metric tons of HAPs would be removed from the turbine exhaust. Again, the CTWG does not have sufficient information to estimate the rate at which catalytic activity would decline in a real-world installation.

VI. COST-EFFECTIVENESS RESULTS

A breakdown of the total HAP reductions achieved for individual pollutants is provided in **Tables 4** and **5**. The cost-effectiveness values based on total HAP reductions are presented in **Table 6** for each model turbine**.** The cost-effectiveness for total HAPs is provided to more fully demonstrate the benefit achieved in terms of total reduction of HAPs for the costs required to install oxidation catalysts. Cost-effectiveness for individual HAPs, calculated as the total annual costs by the mass emissions for each individual HAP, is presented in **Appendix G**. The cost-effectiveness for individual HAPs is presented to show the cost-effectiveness sensitivity for individual HAPs.

In general, the cost per metric ton of reduced HAP emissions is higher for small turbines, because capital costs, on a per-megawatt basis, are highest for these units and the annual HAP emissions are low. The costs per metric ton also would increase for small and large turbines as operating hours decrease because capital costs remain unchanged while annual HAP emissions are lower.

Table 6. Cost-Effectiveness Estimated for Each Model Turbine -- Base Case Analysis

Model Plant	Highest EF: 3-Year Catalyst Life 80% Emissions Reduction	Highest EF: 6-Year Catalyst Life 80% Emissions Reduction	Highest EF: 6-Year Catalyst Life 50% Emissions Reduction	Average EF: 3-Year Catalyst Life 80% Emissions Reduction	Average EF: 6-Year Catalyst Life 80% Emissions Reduction	Average EF: 6-Year Catalyst Life 50% Emissions Reduction
	Cost Effectiveness ($/Mg Total HAPs Reductions*)					
Model 1 -- 85.4 MW Turbine	$69,000	$57,000	$91,000	$450,000	$380,000	$600,000
Model 2 -- 170 MW Turbine	$50,000	$41,000	$66,000	$330,000	$270,000	$440,000
Model 7 -- 39.6 MW Turbine	$81,000	$67,000	$110,000	$530,000	$440,000	$710,000
Model 9 -- 27 MW Turbine	$78,000	$66,000	$100,000	$520,000	$430,000	$690,000
Model 13 -- 3.5 MW Turbine	$290,000	$250,000	$400,000	$1,900,000	$1,700,000	$2,600,000
Model 15 -- 9 MW Turbine	$150,000	$130,000	$200,000	$1,000,000	$840,000	$1,400,000
Model 17 -- 1.13 MW Turbine	$730,000	$630,000	$1,000,000	$4,800,000	$4,100,000	$6,600,000

*Cost-effectiveness values were rounded. Annual costs estimated for each model turbine are presented in **Appendix E**. HAPs reductions estimated for each model turbine are presented in **Tables 4** and **5**. Cost-effectiveness values for individual HAPs are presented in **Appendix G**.

VII. CONCLUSIONS AND RECOMMENDATIONS

The CTWG has assessed the various elements that are relevant to estimation of the cost-effectiveness of oxidation catalysts for control of organic HAPs emitted by combustion turbines. Based on this assessment the CTWG has reached the following conclusions.

1. Using a simplified base case, the annual costs associated with installation and operation of oxidation catalysts for the model turbines ranged from $160,000 for a 1.13 MW unit to $1,700,000 for a 170 MW unit, assuming a three-year catalyst life. Annual costs ranged from $140,000 for a 1.13 MW unit to $1,400,000 for a 170 MW unit, assuming a six-year catalyst life.

2. Based on quantified estimates of emissions, cost, and percent reduction for a simplified base case, the cost-effectiveness of oxidation catalysts for control of total HAPs from combustion turbines ranges from $41,000 per metric ton for a 170 MW unit to $1,000,000 per metric ton for a 1.13 MW unit, assuming emission rates based on the highest reported emission factors for all HAPs. The cost-effectiveness values range from $270,000 for a 170 MW unit to $6,600,000 for a 1.13 MW unit when the average emission factor is used.

3. Because of a variety of complicating factors, it is likely that the base case cost-effectiveness estimated range is lower than the actual cost-effectiveness which would be exhibited by actual application of oxidation catalysts to most combustion turbines in the United States. Key complicating factors include the catalysts life, problems with retrofitting ducts and the catalyst housing at existing facilities, differential effectiveness of the catalysts on various HAP compounds, and fuels that require pre-treatment to avoid fouling the catalyst. In addition, there is uncertainty regarding the HAPs reduction performance included in this base case analysis due to the limited emissions test data available to predict the performance of oxidation catalyst in reducing organic HAP emissions from combustion turbines. While experience with CO oxidation catalysts is useful for evaluating the potential HAP reduction performance, there may be important differences between the costs and performance of CO catalysts and the costs and performance of catalysts for reduction or organic HAPs.

Most of the complicating factors that have not been quantified in the numerical estimates would tend to increase the catalyst costs, or decrease catalyst performance. Because of this, the CTWG views the base case quantitative estimate reported in this paper as a lower range estimate of the cost-effectiveness of oxidation catalysts for HAPs control on combustion turbines.

The CTWG recommends that the Coordinating Committee forward this information to EPA and recommend that EPA consider the information presented in this paper in the Agency's assessment of above-the-floor MACT options for combustion turbines. This paper provides reasonable estimates, based on available information, of the costs and the HAP air emissions reductions that may be achieved with oxidation catalysts. The CTWG recognizes that EPA may consider other factors, such as non-air quality environmental impacts, energy requirements, and secondary pollutants (including possible CO/VOC control), in assessing above-the-floor MACT options.

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Appendix A - List of Model Turbines

Model Plant	Unit	Operating Hours	Heat Recovery	Existing Application	Clean Fuel	Typical Applications	Surrogate	Output	Ex. Flow
1	Large	8000	Y	Y	Y	existing utility/IPP generating station	GE PG 7121EA	85.4	658
1A	Large	8000	Y	Y	N	existing unit with residual oil fuel	GE PG 7121EA	85.4	658
1B	Large	8000	Y	Y	Y	existing utility/IPP generating station (duct burner)	GE PG 7121EA	85.4	658
2	Large	8000	Y	N	Y	new utility/IPP generating station	GE PG 7231FA	170	986
2A	Large	8000	Y	N	N	new unit with residual oil fuel	GE PG 7231FA	170	986
2B	Large	8000	Y	N	Y	new utility/IPP generating station (duct burner)	GE PG 7231FA	170	986
3	Large	2000	N	Y	Y	existing utility/IPP generating station	GE PG 7231FA	170	986
3A	Large	2000	N	Y	Y	existing utility/IPP station (space constrained)	GE PG 7231FA	170	986
4	Large	2000	N	N	Y	new utility/IPP generating station	GE PG 7231FA	170	986
5	Large	500	N	Y	Y	existing utility/IPP peaking unit	GE PG 7121EA	85.4	658
6	Large	500	N	N	Y	new utility/IPP peaking unit	GE PG 7121EA	85.4	658
7	Medium	8000	Y	Y	Y	existing industrial power production	GE PG 6561B	39.6	318
7A	Medium	8000	Y	Y	N	existing unit with residual oil fuel	GE PG 6561B	39.6	318
7B	Medium	8000	Y	Y	Y	existing industrial power production (duct burner)	GE PG 6561B	39.6	318
8	Medium	8000	Y	N	Y	new industrial power production	GE PG 6561B	39.6	318
8A	Medium	8000	Y	N	N	new unit with residual oil fuel	GE PG 6561B	39.6	318
8B	Medium	8000	Y	N	Y	new industrial power production (duct burner)	GE PG 6561B	39.6	318
9	Medium	8000	N	Y	Y	existing pipeline compressor/ ind.- mech. drive	GE LM2500	27	178
10	Medium	8000	N	N	Y	new pipeline compressor/ ind. mech. drive	GE LM2500	27	178
11	Medium	500	N	Y	Y	existing utility/IPP peaking unit	GE PG 6561B	39.6	318
12	Medium	500	N	N	Y	new utility/IPP peaking unit	GE PG 6561B	39.6	318
13	Small	8000	Y	Y	Y	existing industrial process plant (food, nat'l gas)	Solar Centaur 40	3.5	41
13A	Small	8000	Y	Y	N	existing landfill operation or residual oil fuel	Solar Centaur 40	3.5	41
13B	Small	8000	Y	Y	Y	existing ind. process plant (duct burner)	Solar Centaur 40	3.5	41
14	Small	8000	Y	N	Y	new industrial process plant (food, nat'l gas)	Solar Centaur 40	3.5	41
14A	Small	8000	Y	N	N	new landfill operation or residual oil fuel	Solar Centaur 40	3.5	41
14B	Small	8000	Y	N	Y	new ind. process plant (duct burner)	Solar Centaur 40	3.5	41
15	Small	8000	N	Y	Y	existing pipeline compressor	Solar Mars T12000	9	83.6
15A	Small	8000	N	Y	Y	existing offshore platform (space constrained)	Solar Mars T12000	9	83.6
16	Small	8000	N	N	Y	new pipeline compressor/offshore platform	Solar Mars T12000	9	83.6
17	Small	200	N	Y	Y	existing emergency power (hospital,university,etc)	Solar Saturn T1500	1.13	14.2
18	Small	200	N	N	Y	new emergency power (hospital, university, etc)	Solar Saturn T1500	1.13	14.2

Appendix B - Description of ICCR Emissions Database

MEMORANDUM

DATE : March 6, 1998
SUBJECT : Documentation on the Combustion Turbines Emissions Database
TO : Combustion Turbines Project File
FROM : Ana Rosa Alvarez and Dan Herndon

This memorandum provides a short description of the development of the emissions database for turbines, including assumptions used in the underlying calculations.

Development of the Emissions Database

The emission test reports were first carefully reviewed and summarized. Facility name, location, testing company, date of testing, make and model of turbine, manufacturer rating (and units), load, fuel type, application and control device (for emissions) were entered in a table named ?Facilities.? Pollutant name, sampling method, concentrations and units, detection limits and units, % oxygen, fuel factors, exhaust gas flow rates, stack temperature, fuel heating value and flow rate, % humidity, standard temperature, and pollutant molecular weight were entered in a table named ?Test Data.? Emission rates (lb/hr) and emission factors (lb/MMBtu) were also entered in that table for comparison with the emissions calculated in the database using the pollutant concentrations for each test run.

Test reports included in the database were identified using the following scheme: numbers from 1 to 99 were assigned to tests containing only hazardous air pollutants (HAPs), and numbers greater than 100 were allocated for tests with only criteria pollutants or with both HAPs and criteria pollutants. Exceptions are the reports numbered 10 and 15. These test reports contain both HAPs and criteria pollutant test results. They are numbered as HAPs-only type reports because criteria pollutant data were identified in these reports after the first version of the database was posted on the TTN. Test reports containing more than one turbine, multiple load conditions, different fuels, control device inlet and outlet samples (criteria pollutant data only), or more than three sampling runs were assigned the same initial number followed by an extension (for example, 1.1 or 1.1.1).

Some of the test reports in the database include an ?x? symbol at the end of the test report number (e.g., test report 8x). The ?x? symbol indicates that the test report does not meet the acceptance criteria developed by the CTWG. The data from these test reports are included in the database for informational purposes only.

Construction of database reports (i.e., summaries of relevant data) required the complete separation of tests with HAPs-only data from tests with only criteria pollutant data and tests with both HAPs and criteria pollutant data. The ?Test Data? table was consequently divided into three tables: ?Test Data - HAPs,? containing all HAP data in the Test Data table; ?Test Data - Criteria Pollutants,? containing all criteria pollutant data in the Test Data table, and ?Test Data - HAPs + Criteria,? containing the tests that include data for both HAPs and criteria pollutants.

In the report section, a set of 6 different reports was built for each of the test data tables discussed above. These reports provide information about pollutant concentrations (corrected to 15% O_2) and emissions in units of lb/hr, lb/MMBtu, and lb/MW-hr. Individual sets of reports were also developed for test summaries and pollutant summaries.

Treatment of non-detected or non-reported concentrations

Many pollutants, especially HAPs, were not detected in some or all of the sampling runs collected during a test. In these cases, concentrations were entered in the database as ?ND.? Although the test reports identified those pollutants not detected for a given testing run, the detection limit (DL) values were not always provided (i.e., ND was reported rather than a detection limit concentration). Often, review of the lab report and some additional calculations were necessary to determine the DL concentration. For example, in the case of formaldehyde, detection limits were usually given in micrograms or micrograms per milliliter in the lab report. Estimation of the DL in the same units as the test data (e.g., ppb) involved the use of the sample volume collected during the test and additional unit conversions (for example, micrograms/cubic meter to ppb).

Unfortunately, the DL could not always be found or calculated based on the laboratory report. Whenever a pollutant was not detected in all three runs and the DL could not be determined, the pollutant was removed from the database. This procedure was used for report ID #1 for benzene and chromium (VI). Also, due to the calculations discussed above, two or three different DLs (one per testing run) were determined for the same pollutant in some tests. The protocol followed in these cases was to take the highest DL value.

In some tests, only one or two runs were conducted, or runs were eliminated during test report preparation due to sampling problems encountered during the test. Missing runs were entered as NR (not reported) in the database. Other parameters missing from the test reports, such as exhaust gas flow rates, were also entered in the database as NR.

The acronym NA sometimes appears in the DL field. This acronym is used in those cases when a pollutant was measured above the detection limit in all of the testing runs but a detection limit value was not reported in the test report.

Equations

Using raw test data (i.e., lab-reported pollutant concentrations and stack test parameters), calculations were performed to estimate emissions in lb/hr, lb/MW-hr and lb/MMBtu. Modules, small programs written in Visual Basic code, were built to perform the calculations. There are various modules in the emissions database that perform different tasks, but only the main modules are described in this memorandum.

The equations used in the modules were taken from EPA sampling methods 19 and 20 in 40 CFR Part 60, Appendix A. For example, for the correction of the dry pollutant concentration to 15% O_2, Equation 20-4 from EPA method 20 is used:

$$C_{adj} = C_d * \frac{20.9 - 15}{20.9 - \% O_2}$$

where $\%O_2$ refers to the reported oxygen level during the testing and C_d to the pollutant dry concentration in ppb.

For the calculation of emission rates in lb/hr, lb/MW-hr, and lb/MMBtu, the following equations were used :

1. Pounds per hour:

When the concentration of pollutant is given in ppb :

$$M(lb/hr) = C_{ppb} * Q * 60 * \frac{MW}{T_{std} + 460} * 1.369x10^{-9}$$

where C_{ppb} is the dry concentration of pollutant in ppb; Q is the exhaust gas flow rate in dry standard cubic feet per minute; 60 is the conversion factor from minutes to hours; MW is the pollutant molecular weight (in lb/lb-mol); T_{std} is the standard temperature in degrees Fahrenheit used in the test report; 460 is the conversion factor from degrees Fahrenheit to degrees Rankine; and $1.369x10^{-9}$ is the conversion factor from ppb to pounds per cubic feet. The conversion factor from ppb to pounds per cubic feet was derived from 40 CFR, App. A, Meth. 20, page 1026.

When the concentration of a pollutant is given in units other than ppb or ppm, the equation is :

$$M(lb/hr) = C_p * Q * 60 * A$$

where C_p is the concentration of pollutant in micrograms per dry cubic feet (ug/dscf), micrograms per dry cubic meter (ug/dscm), grams per dry cubic feet (g/dscf) or grams per dry cubic meter (g/dscm). For particulate matter, concentrations are in grains per dry cubic feet (gr/dscf), grains per dry cubic meter (gr/dscm), micrograins per dry cubic feet (ugr/dscf) and micrograins per dry cubic meter (ugr/dscm). Q is the exhaust gas flow rate in dry standard cubic feet per minute; 60 is the conversion factor from minutes to hours; and A is a conversion factor from the given units to lb/dscf.

The values for A for the different units are:

1.1 For ug/dscf, A = $2.205x10^{-8}$
1.2 For ug/dscm, A = $6.24x10^{-10}$
1.3 For g/dscf and g/dscm, multiplying 1.1 and 1.2 by $1x10^{-6}$
1.4 For ugr/dscf, A = $1.43x10^{-10}$.
1.5 For ugr/dscm, A = $4.043x10^{-12}$.
1.6 For gr/dscf and gr/dscm, multiplying 1.4 and 1.5 by $1x10^{-6}$

2. Pounds per megawatt-hour:

The emission factor is calculated by dividing the emissions rate in lb/hr by the turbine rating during the test. The manufacturer rating and the test load are necessary data for this calculation. When load was not available, it was assumed to be 100%. The equation is :

$$M(lb/MW-hr) = \frac{M(lb/hr)}{\frac{R * L}{100}}$$

where M(lb/hr) is the emission rate in lb/hr; R is the manufacturer rating for the turbine in MW; and L is the turbine testing load in %. The equation is :

3. Pounds per million Btu:

$$M(lb/MMBtu) = C_p * F * \frac{20.9}{20.9 - \%O_2} * B * \left(\frac{MW}{T_{std} + 460}\right)$$

where C_p is the dry concentration of pollutant in any of the units already described for the calculation of emission factors (1.1 - 1.6); F is the fuel factor in dry standard cubic feet per minute per million Btu; the fraction $20.9/(20.9\text{-}\%O_2)$ is an oxygen correction factor; and B is the conversion factor corresponding to the units in which the pollutant concentration is reported (see the units described in 1.1 - 1.6). The fraction $MW/(T_{std}+460)$ is a conversion factor used only when the pollutant concentration was provided in ppb.

When the fuel factor or standard temperature was not available, defaults were used. These defaults are discussed in next section.

A sample of the modules used for the calculations is provided in Appendix C-1.

Defaults and Assumptions

For the estimation of emission factors from the concentrations given in ppb, gaseous pollutants were assumed to have ideal gas behavior, so that the volume occupied by an ideal gas (22.4 liters/mol) could be used for calculation of a conversion factor.

Not all of the reports contained the necessary information required for the calculation of emission factors. Important parameters are concentrations, units, detection limits, oxygen levels, exhaust gas flow rates, fuel factors, standard temperatures and molecular weights. In most cases, fuel factors and standard temperatures were missing. In some cases, exhaust gas flow rates were not provided in the report. Lack of gas flow rates still allows for the calculation of emission factors in pounds per million Btu. Consequently, tests lacking exhaust gas flow rates were kept in the database, but the emissions in pound per hour are shown as NR.

For non-methane hydrocarbons (NMHC) and total hydrocarbons (THC), a molecular weight of 16 (as methane) was assumed. Test reports in the database indicated a molecular weight of 16 for THC and, in most cases, for NMHC. However, in some test reports, the molecular weight chosen to report emission factors for NMHC was the molecular weight of hexane.

Fields with NR for fuel factors and standard temperatures were filled with default values based on Table 19-1 in 40 CFR Part 60, Appendix A. A default standard temperature of 68^{o}F was used. This standard temperature was selected because EPA sampling methods rely on this value.

As discussed earlier, some pollutants were not detected in one or more of the sampling runs conducted during a test. In these cases, the detection limit was used in the emission calculations. Reports generated in the emissions database use a ?<? sign in front of the sampling run concentration, as well as the average concentration calculated for the three runs, to indicate when a pollutant was not detected in one or more of the runs. When a pollutant was not detected in all three runs, a ?<<? sign is shown in front of the average concentration presented in the database reports. The DL value was used in calculating the average concentration when a pollutant was not detected in one or more of the runs.

Appendix C-1

Sample of modules used in the database

The modules shown here are the modules for the calculation of emission factors in pounds per million Btu (Module Convert) and the module that handles the criteria for the use of detection limits (Module NonDetect).

1. Module for the calculation of emission factors in pounds per million Btu

1.1 Declaring the function that will perform the calculations and return the result to the query. The parameters r, s, t, u, v, w, z refer to concentration units (r), fuel factor (s), molecular weight (t), standard temperature (u), % oxygen (v), concentration (w), and a parameter (z, set to three in the database) used to limit the number of significant digits (utilizing another module) in the result.

```
Function lbMMBtu (r, s, t, u, v, w, x, y, z)
```

1.2 Estimating the emission factor to return to the query that is calling this module. First the module identifies the units (r=ppb), then it makes sure that there are values in all necessary fields and finally performs the calculation. SigDig_ is calling another module that will perform the reduction of the result to a given number (z) of significant digits. Val calls for the numerical value of the field being processed.

```
If ((r = "ppb") And Not (s = "NR" Or t = "NR" Or v = "NR" Or w = "NR")) Then
lbMMBtu = CStr(SigDig_((Val(s) * Val(t) * (.00000000137 / (Val(u) + 460)) * (20.9 / (20.9 - Val(v))) * Val(w)), z))

ElseIf ((r = "ug/dscm") And Not (s = "NR" Or v = "NR" Or w = "NR")) Then
    lbMMBtu = CStr(SigDig_((Val(s) * Val(w) * .0283 * .000000002204 * (20.9 / (20.9 - Val(v)))), z))

ElseIf ((r = "ug/dscf") And Not (s = "NR" Or v = "NR" Or w = "NR")) Then
    lbMMBtu = CStr(SigDig_((Val(s) * Val(w) * .000000002204 * (20.9 / (20.9 - Val(v)))), z))

ElseIf ((r = "gr/dscf") And Not (s = "NR" Or v = "NR" Or w = "NR")) Then
    lbMMBtu = CStr(SigDig_((Val(s) * Val(w) * (20.9 / (20.9 - Val(v))) / 7000), z))

ElseIf ((r = "ugr/dscm") And Not (s = "NR" Or v = "NR" Or w = "NR")) Then
    lbMMBtu = CStr(SigDig_((Val(s) * Val(w) * .0283 * (20.9 / (20.9 - Val(v))) * 0.000001 / 7000), z))

ElseIf ((r = "gr/dscm") And Not (s = "NR" Or v = "NR" Or w = "NR")) Then
    lbMMBtu = CStr(SigDig_((Val(s) * Val(w) * .0283 * (20.9 / (20.9 - Val(v))) / 7000), z))
```

1.3 In any other case (units not recognized or necessary parameters were not reported) the function is returned with the value ?NR?

```
Else          lbMMBtu = "NR"          End If      End Function
```

2. <u>Module Handling the use of non-detected values</u>

2.1 Declaring the function that will return the values to the query. The parameters x and y refer respectively to concentration and detection limit.

Function Correction (x, y)

2.2 Identifying the concentration. If it is not reported, return the value ?NR;? if it is not detected, take the value of the detection limit as the value for the concentration to be returned. Otherwise leave the value as it is.

If (x = "NR") Then Correction = "NR" ElseIf
If (x = "ND") Then Correction = y Else
Correction = x End If
End Function

Appendix C -- QA\QC Review Criteria for Emissions Tests

HAPS and Criteria Pollutant Source Test Checklist

	Source Test Report #____ Date__________	Source Test Report #____ Date__________
BASIC TURBINE INFORMATION		
Manufacturer	______________	______________
Model #	______________	______________
Rating (BHP or MW)	______________	______________
Operating Cycle (Simple, Regenerative, etc.)	______________	______________
FUEL DESCRIPTION		
Fuel Name(s)	______________	______________
Fuel Analysis Summary	______________	______________
Flowrate (or BTU/H, if available)	______________	______________
OPERATING CONDITIONS		
Load (during test)	______________	______________
Water or Steam Injection and/or Ammonia Mass Flowrate	______________	______________
Firing Temperature or Turbine Inlet Temperature	______________	______________
AMBIENT CONDITIONS		
Temperature	______________	______________
Relative Humidity	______________	______________
Barometric Pressure	______________	______________
Altitude	______________	______________
EXHAUST INFORMATION		
Temperature	______________	______________
Flowrate (F-Factor or Measured)	______________	______________
EMISSIONS TEST		
*Criteria Pollutants	______________	______________
HAPS	______________	______________
Oxygen or CO_2	______________	______________
Moisture	______________	______________
Averaging Time	______________	______________
METHODS USED		
CARB	______________	______________
EPA	______________	______________
Other ____________________	______________	______________
QUALITY CONTROL DOCUMENTATION		
Calibration of Instruments	______________	______________
Specialty Gases	______________	______________
CEMs	______________	______________
Dry Gas Meters	______________	______________
MISCELLANEOUS		
Limits of Detection Reporting	______________	______________
Supplemental Firing Details	______________	______________

Appendix D

Development of Emission Factors (lb/MMBtu) for Natural Gas Fired Turbines

The emission factors (lb/MMBtu) presented in Table 1 were calculated for natural gas-fired turbines from 23 source test reports in the emissions database. Emission factors from test reports that did not meet acceptance criteria established by the CTWG were not used in the calculations (4.1.2x, 8x, 10x, 29.1, 29.2, and 29.3). In addition, only test reports where the testing was conducted at high loads (greater than 80%) were included in the analysis. Test reports in which the load was not specified in the test report or could not be estimated from fuel use data were excluded.

The following test reports were used for the emission factor calculations: 2, 3.1, 4.2, 6.2, 7, 9, 11, 12.1, 13.1, 15.1, 17, 18, 22, 26, 27, 28, 313.1.1x, 313.2.1x, 314.1x, 315.1x, 316.1.1x, 316.2.1x, and 317.1x. Listed below are the source test reports that were excluded from the emission factor calculation with the reason for exclusion.

Test Report ID#	**Reason for Exclusion**
4.1.2x	Formaldehyde data point appears to be an outlier. Retest of the
8x	Report deemed inadequate by state and federal regulators
10x	Missing load and fuel usage data.
29.1, 29.2, 29.3	Only summary data provided; no raw data sheets, laboratory
16, 21, 313.1.2x,	Testing occurred only at operating loads less than 80%**.**
23, 25	Load information not available.

Test data for individual HAPs that were not detected in any of the sampling runs for a source test (i.e., where the concentration was ND in all three runs) were excluded from the emission factor calculation for that HAP. This exclusion was made on a pollutant basis such that data for a subset of the HAPs analyzed for in a particular source test may have been used.

Appendix E -- Cost Spreadsheets

INPUTS AND CALCULATIONS

Model Turbine Number	1	
Turbine Exhaust Flow (lb/sec)	658	
Turbine Rating (MW)	85.4	
Turbine Rating (hp)	114523.1	
Heat Input, MMBtu/hr, including	832.5656	(Rating in MW / .29307 MW/MMBTU/hr)/ Efficiency
Hours of operation/yr	8000	
Life of equipment	15	
Life of catalyst	3 or 6 Years	
Interest rate (fraction)	0.07	
Capital Recovery Factor,	0.109795	
Capital Recovery Factor, 3-yr	0.381052	
Capital Recovery Factor, 6-yr	0.209796	
Destruction Efficiency - 3-yr & 6-yr	80	for emission reduction calculation
Destruction Efficiency - 6-yr	50	for emission reduction calculation
VAPCCI Escalator		
Fuel Type (CLEAN OR DIRTY)	CLEAN	
Turbine Assumed Efficiency	0.35	for emission reduction calculation
Turbine Exhaust Temp (0F)	1000	

Catalyst Calculations:

Vendor Estimate - Based on 80 Percent Reduction of Formaldehyde

Catalyst, Frame &	1595574	Per Catalyst Vendors, assume housing is 30 percent of Total Catalyst Costs
Catalyst only	1116874	EPA formula based on Vendor Quotes
Ductwork	(No quantitative estimates available)	

COSTS	(Patterned after the OAQPS Cost Manual (1990) Thermal and Catalytic Incinerators Section)			
Direct Costs			3-Year	6-Year Costs
Purchased Equipment Costs (PEC)				
	Catalyst + auxiliary equipment* (EC)	1 EC	1595574	1595574
	Instrumentation**	0.1 EC	159557.4	159557.4
	Sales Tax	0.03 EC	47867.23	47867.23
	Freight	0.05 EC	79778.72	79778.72
	Total Purchased Equipment Cost,	1.18 EC	1882778	1882778
Direct Installation Costs				
	Foundations & supports	0.08 PEC	150622.2	150622.2
	Handling & erection	0.14 PEC	263588.9	263588.9
	Electrical	0.04 PEC	75311.11	75311.11
	Piping	0.02 PEC	37655.56	37655.56
	Insulation for ductwork	0.01 PEC	18827.78	18827.78
	Painting	0.01 PEC	18827.78	18827.78
	Direct Installation Cost	0.3 PEC	564833.3	564833.3
Site preparation		As required, SP	0	0
Buildings		As required, Bldg.	0	0
	Total Direct Cost, DC	1.30 PEC + SP +	2447611	2447611
Indirect Costs (installation)				
	Engineering	0.1 PEC	188277.8	188277.8
	Construction and Field Expenses	0.05 PEC	94138.89	94138.89
	Contractor Fees	0.1 PEC	188277.8	188277.8
	Start-up	0.02 PEC	37655.56	37655.56
	Performance test	0.01 PEC	18827.78	18827.78
	Total Indirect Cost, IC	0.28 PEC	527177.8	527177.8
	Contingencies	0.1 DC+IC	297478.9	297478.9
	Total Capital Cost (TCC) = DC + IC +	1.61 PEC + SP +	3272268	3272268

Direct Annual Cost (DAC)

Fuel	Fuel Penalty due to		1		17320	17320
Perf. Test	Performance Test				5000	5000
Cat. Costs	Freight to return		Freight=.05*Catalyst only cost*[i/[(1+i)^n-1],		17370.28	7806.717
	Catalyst replacement		Catalyst only cost * CRFcat		425586.9	234315.6
Operating Labor						
	Operator	2 hours	Per Engine ACT-NSCR		18250	18250
	Supervisor	.15 *OL		0.15 OL	2737.5	2737.5
Maintenance						
	Labor &	.10 PEC	Per Engine ACT-	0.1 PEC	188277.8	188277.8
		Total Direct Annual Cost (DAC)			674542.4	473707.6

Indirect Annual Cost (IAC)

Overhead			0.6 O&M	125559.2	125559.2
Administrative			0.02 TCC	65445.36	65445.36
Property Taxes			0.01 TCC	32722.68	32722.68
Insurance			0.01 TCC	32722.68	32722.68
Capital	for catalyst:	CRFequip(TCC - 1.08(Cat only))		226840.5	226840.5
		Total Indirect Annual Cost (IAC)		483290.3	483290.3
	Total Annual Cost (TAC)			1157833	956997.9

INPUTS AND CALCULATIONS

Model Turbine Number	2	
Turbine Exhaust Flow (lb/sec)	986	
Turbine Rating (MW)	170	
Turbine Rating (hp)	227973.4	
Heat Input, MMBtu/hr, including	1657.332	(Rating in MW / .29307 MW/MMBTU/hr)/ Efficiency
Hours of operation/yr	8000	
Life of equipment	15	
Life of catalyst	3 or 6 Years	
Interest rate (fraction)	0.07	
Capital Recovery Factor,	0.109795	
Capital Recovery Factor, 3-yr	0.381052	
Capital Recovery Factor, 6-yr	0.209796	
Destruction Efficiency - 3-yr & 6-	80	for emission reduction calculation
Destruction Efficiency - 6-yr	50	for emission reduction calculation
VAPCCI Escalator		
Fuel Type (CLEAN OR DIRTY)	CLEAN	
Turbine Assumed Efficiency	0.35	for emission reduction calculation
Turbine Exhaust Temp (0F)	1000	

Catalyst Calculations:

Vendor Estimate - Based on 80 Percent Reduction of Formaldehyde

Catalyst, Frame &	2317985	Per Catalyst Vendors, assume housing is 30 percent of Total Catalyst Costs
Catalyst only	1622585	EPA formula based on Vendor Quotes
Ductwork	(No quantitative estimates available)	

COSTS	(Patterned after the OAQPS Cost Manual (1990) Thermal and Catalytic Incinerators Section)			
Direct Costs			3-Year	6-Year Costs
Purchased Equipment Costs (PEC)				
Catalyst + auxiliary equipment* (EC)		1 EC	2317985	2317985
Instrumentation**		0.1 EC	231798.5	231798.5
Sales Tax		0.03 EC	69539.54	69539.54
Freight		0.05 EC	115899.2	115899.2
	Total Purchased Equipment Cost,	1.18 EC	2735222	2735222
Direct Installation Costs				
Foundations & supports		0.08 PEC	218817.8	218817.8
Handling & erection		0.14 PEC	382931.1	382931.1
Electrical		0.04 PEC	109408.9	109408.9
Piping		0.02 PEC	54704.44	54704.44
Insulation for ductwork		0.01 PEC	27352.22	27352.22
Painting		0.01 PEC	27352.22	27352.22
	Direct Installation Cost	0.3 PEC	820566.6	820566.6
Site preparation		As required, SP	0	0
Buildings		As required, Bldg.	0	0
	Total Direct Cost, DC	1.30 PEC + SP +	3555789	3555789
Indirect Costs (installation)				
Engineering		0.1 PEC	273522.2	273522.2
Construction and Field Expenses		0.05 PEC	136761.1	136761.1
Contractor Fees		0.1 PEC	273522.2	273522.2
Start-up		0.02 PEC	54704.44	54704.44
Performance test		0.01 PEC	27352.22	27352.22
	Total Indirect Cost, IC	0.28 PEC	765862.2	765862.2
Contingencies		0.1 DC+IC	432165.1	432165.1
Total Capital Cost (TCC) = DC + IC +		1.61 PEC + SP +	4753816	4753816

Direct Annual Cost (DAC)

Fuel	Fuel Penalty due to		1		34470	34470
Perf. Test	Performance Test				5000	5000
Cat. Costs	Freight to return		Freight=.05*Catalyst only cost*[i/[(1+i)^n-1],		25235.39	11341.53
	Catalyst replacement		Catalyst only cost * CRFcat		618288.6	340411.5
Operating Labor						
	Operator	2 hours	Per Engine ACT-NSCR		18250	18250
	Supervisor	.15 *OL		0.15 OL	2737.5	2737.5
Maintenance						
	Labor &	.10 PEC	Per Engine ACT-	0.1 PEC	273522.2	273522.2
		Total Direct Annual Cost (DAC)			977503.7	685732.7

Indirect Annual Cost (IAC)

Overhead			0.6 O&M	176705.8	176705.8
Administrative			0.02 TCC	95076.32	95076.32
Property Taxes			0.01 TCC	47538.16	47538.16
Insurance			0.01 TCC	47538.16	47538.16
Capital	for catalyst: CRFequip(TCC - 1.08(Cat only))			329540.3	329540.3
		Total Indirect Annual Cost (IAC)		696398.7	696398.7
	Total Annual Cost (TAC)			1673902	1382131

INPUTS AND CALCULATIONS

Model Turbine Number	7	
Turbine Exhaust Flow (lb/sec)	318	
Turbine Rating (MW)	39.6	
Turbine Rating (hp)	53104.39	
Heat Input, MMBtu/hr, including	386.0609	(Rating in MW / .29307 MW/MMBTU/hr)/ Efficiency
Hours of operation/yr	8000	
Life of equipment	15	
Life of catalyst	3 or 6 Years	
Interest rate (fraction)	0.07	
Capital Recovery Factor,	0.109795	
Capital Recovery Factor, 3-yr	0.381052	
Capital Recovery Factor, 6-yr	0.209796	
Destruction Efficiency - 3-yr & 6-	80	for emission reduction calculation
Destruction Efficiency - 6-yr	50	for emission reduction calculation
VAPCCI Escalator		
Fuel Type (CLEAN OR DIRTY)	CLEAN	
Turbine Assumed Efficiency	0.35	for emission reduction calculation
Turbine Exhaust Temp (0F)	1000	

Catalyst Calculations:

Vendor Estimate - Based on 80 Percent Reduction of Formaldehyde

Catalyst, Frame &	846662.4	Per Catalyst Vendors, assume housing is 30 percent of Total Catalyst Costs
Catalyst only	592662.4	EPA formula based on Vendor Quotes
Ductwork	(No quantitative estimates available)	

COSTS (Patterned after the OAQPS Cost Manual (1990) Thermal and Catalytic Incinerators Section)

			3-Year	6-Year Costs
Direct Costs				
Purchased Equipment Costs (PEC)				
	Catalyst + auxiliary equipment* (EC)	1 EC	846662.4	846662.4
	Instrumentation**	0.1 EC	84666.24	84666.24
	Sales Tax	0.03 EC	25399.87	25399.87
	Freight	0.05 EC	42333.12	42333.12
	Total Purchased Equipment Cost,	1.18 EC	999061.6	999061.6
Direct Installation Costs				
	Foundations & supports	0.08 PEC	79924.93	79924.93
	Handling & erection	0.14 PEC	139868.6	139868.6
	Electrical	0.04 PEC	39962.47	39962.47
	Piping	0.02 PEC	19981.23	19981.23
	Insulation for ductwork	0.01 PEC	9990.616	9990.616
	Painting	0.01 PEC	9990.616	9990.616
	Direct Installation Cost	0.3 PEC	299718.5	299718.5
Site preparation		As required, SP	0	0
Buildings		As required, Bldg.	0	0
	Total Direct Cost, DC	1.30 PEC + SP +	1298780	1298780
Indirect Costs (installation)				
	Engineering	0.1 PEC	99906.16	99906.16
	Construction and Field Expenses	0.05 PEC	49953.08	49953.08
	Contractor Fees	0.1 PEC	99906.16	99906.16
	Start-up	0.02 PEC	19981.23	19981.23
	Performance test	0.01 PEC	9990.616	9990.616
	Total Indirect Cost, IC	0.28 PEC	279737.3	279737.3
	Contingencies	0.1 DC+IC	157851.7	157851.7
	Total Capital Cost (TCC) = DC + IC +	1.61 PEC + SP +	1736369	1736369

Direct Annual Cost (DAC)

Fuel	Fuel Penalty due to		1		8030	8030
Perf. Test	Performance Test				5000	5000
Cat. Costs	Freight to return		Freight=.05*Catalyst only cost*[i/[(1+i)^n-1],		9217.431	4142.586
	Catalyst replacement		Catalyst only cost * CRFcat		225835	124338.1
Operating Labor						
	Operator	2 hours	Per Engine ACT-NSCR		18250	18250
	Supervisor	.15 *OL		0.15 OL	2737.5	2737.5
Maintenance						
	Labor &	.10 PEC	Per Engine ACT-	0.1 PEC	99906.16	99906.16
		Total Direct Annual Cost (DAC)			368976.1	262404.3

Indirect Annual Cost (IAC)

Overhead			0.6 O&M	72536.2	72536.2
Administrative			0.02 TCC	34727.38	34727.38
Property Taxes			0.01 TCC	17363.69	17363.69
Insurance			0.01 TCC	17363.69	17363.69
Capital	for catalyst: CRFequip(TCC - 1.08(Cat only))			120367.2	120367.2
		Total Indirect Annual Cost (IAC)		262358.1	262358.1
	Total Annual Cost (TAC)			631334.2	524762.5

INPUTS AND CALCULATIONS

Model Turbine Number	9	
Turbine Exhaust Flow (lb/sec)	178	
Turbine Rating (MW)	27	
Turbine Rating (hp)	36207.54	
Heat Input, MMBtu/hr, including	263.2233	(Rating in MW / .29307 MW/MMBTU/hr)/ Efficiency
Hours of operation/yr	8000	
Life of equipment	15	
Life of catalyst	3 or 6 Years	
Interest rate (fraction)	0.07	
Capital Recovery Factor,	0.109795	
Capital Recovery Factor, 3-yr	0.381052	
Capital Recovery Factor, 6-yr	0.209796	
Destruction Efficiency - 3-yr & 6-yr	80	for emission reduction calculation
Destruction Efficiency - 6-yr	50	for emission reduction calculation
VAPCCI Escalator		
Fuel Type (CLEAN OR DIRTY)	CLEAN	
Turbine Assumed Efficiency	0.35	for emission reduction calculation
Turbine Exhaust Temp (0F)	1000	

Catalyst Calculations:

Vendor Estimate - Based on 80 Percent Reduction of Formaldehyde

Catalyst, Frame &	538310.4	Per Catalyst Vendors, assume housing is 30 percent of Total Catalyst Costs
Catalyst only	376810.4	EPA formula based on Vendor Quotes
Ductwork	(No quantitative estimates available)	

COSTS (Patterned after the OAQPS Cost Manual (1990) Thermal and Catalytic Incinerators Section)

Cost Item		3-Year	6-Year Costs
Direct Costs			
Purchased Equipment Costs (PEC)			
Catalyst + auxiliary equipment* (EC)	1 EC	538310.4	538310.4
Instrumentation**	0.1 EC	53831.04	53831.04
Sales Tax	0.03 EC	16149.31	16149.31
Freight	0.05 EC	26915.52	26915.52
Total Purchased Equipment Cost,	1.18 EC	635206.3	635206.3
Direct Installation Costs			
Foundations & supports	0.08 PEC	50816.5	50816.5
Handling & erection	0.14 PEC	88928.88	88928.88
Electrical	0.04 PEC	25408.25	25408.25
Piping	0.02 PEC	12704.13	12704.13
Insulation for ductwork	0.01 PEC	6352.063	6352.063
Painting	0.01 PEC	6352.063	6352.063
Direct Installation Cost	0.3 PEC	190561.9	190561.9
Site preparation	As required, SP	0	0
Buildings	As required, Bldg.	0	0
Total Direct Cost, DC	1.30 PEC + SP +	825768.2	825768.2
Indirect Costs (installation)			
Engineering	0.1 PEC	63520.63	63520.63
Construction and Field Expenses	0.05 PEC	31760.31	31760.31
Contractor Fees	0.1 PEC	63520.63	63520.63
Start-up	0.02 PEC	12704.13	12704.13
Performance test	0.01 PEC	6352.063	6352.063
Total Indirect Cost, IC	0.28 PEC	177857.8	177857.8
Contingencies	0.1 DC+IC	100362.6	100362.6
Total Capital Cost (TCC) = DC + IC +	1.61 PEC + SP +	1103989	1103989
Direct Annual Cost (DAC)			

	Fuel	Fuel Penalty due to		1		5470	5470
	Perf. Test	Performance Test				5000	5000
	Cat. Costs	Freight to return		Freight=.05*Catalyst only cost*[i/[(1+i)^n-1],		5860.375	2633.826
		Catalyst replacement		Catalyst only cost * CRFcat		143584.2	79053.24
	Operating Labor						
		Operator	2 hours	Per Engine ACT-NSCR		18250	18250
		Supervisor	.15 *OL		0.15 OL	2737.5	2737.5
	Maintenance						
		Labor &	.10 PEC	Per Engine ACT-	0.1 PEC	63520.63	63520.63
			Total Direct Annual Cost (DAC)			244422.7	176665.2
Indirect Annual Cost (IAC)							
	Overhead				0.6 O&M	50704.88	50704.88
	Administrative				0.02 TCC	22079.77	22079.77
	Property Taxes				0.01 TCC	11039.89	11039.89
	Insurance				0.01 TCC	11039.89	11039.89
	Capital	for catalyst: CRFequip(TCC - 1.08(Cat only))				76530.51	76530.51
			Total Indirect Annual Cost (IAC)			171394.9	171394.9
		Total Annual Cost (TAC)				415817.7	348060.1

INPUTS AND CALCULATIONS

Model Turbine Number	15	
Turbine Exhaust Flow (lb/sec)	83.6	
Turbine Rating (MW)	9	
Turbine Rating (hp)	12069.18	
Heat Input, MMBtu/hr, including	87.74111	(Rating in MW / .29307 MW/MMBTU/hr)/ Efficiency
Hours of operation/yr	8000	
Life of equipment	15	
Life of catalyst	3 or 6 Years	
Interest rate (fraction)	0.07	
Capital Recovery Factor,	0.109795	
Capital Recovery Factor, 3-yr	0.381052	
Capital Recovery Factor, 6-yr	0.209796	
Destruction Efficiency - 3-yr & 6-yr	80	for emission reduction calculation
Destruction Efficiency - 6-yr	50	for emission reduction calculation
VAPCCI Escalator		
Fuel Type (CLEAN OR DIRTY)	CLEAN	
Turbine Assumed Efficiency	0.35	for emission reduction calculation
Turbine Exhaust Temp (0F)	1000	

Catalyst Calculations:

Vendor Estimate - Based on 80 Percent Reduction of Formaldehyde

Catalyst, Frame &	330364.5	Per Catalyst Vendors, assume housing is 30 percent of Total Catalyst Costs
Catalyst only	231264.5	EPA formula based on Vendor Quotes
Ductwork	(No quantitative estimates available)	

COSTS (Patterned after the OAQPS Cost Manual (1990) Thermal and Catalytic Incinerators Section)			
Direct Costs		3-Year	6-Year Costs
Purchased Equipment Costs (PEC)			
Catalyst + auxiliary equipment* (EC)	1 EC	$236,584	$236,584
Instrumentation**	0.1 EC	$23,658	$23,658
Sales Tax	0.03 EC	$7,098	$7,098
Freight	0.05 EC	$11,829	$11,829
Total Purchased Equipment Cost,	1.18 EC	$279,169	$279,169
Direct Installation Costs			
Foundations & supports	0.08 PEC	$22,334	$22,334
Handling & erection	0.14 PEC	$39,084	$39,084
Electrical	0.04 PEC	$11,167	$11,167
Piping	0.02 PEC	$5,583	$5,583
Insulation for ductwork	0.01 PEC	$2,792	$2,792
Painting	0.01 PEC	$2,792	$2,792
Direct Installation Cost	0.3 PEC	$83,751	$83,751
Site preparation	As required, SP	$0	$0
Buildings	As required, Bldg.	$0	$0
Total Direct Cost, DC	1.30 PEC + SP +	$362,920	$362,920
Indirect Costs (installation)			
Engineering	0.1 PEC	$27,917	$27,917
Construction and Field Expenses	0.05 PEC	$13,958	$13,958
Contractor Fees	0.1 PEC	$27,917	$27,917
Start-up	0.02 PEC	$5,583	$5,583
Performance test	0.01 PEC	$2,792	$2,792
Total Indirect Cost, IC	0.28 PEC	$78,167	$78,167
Contingencies	0.1 DC+IC	$44,109	$44,109
Total Capital Cost (TCC) = DC + IC +	1.61 PEC + SP +	$485,196	$485,196

Direct Annual Cost (DAC)

			3-Year	6-Year Costs
Direct Costs				
Purchased Equipment Costs (PEC)				
	Catalyst + auxiliary equipment* (EC)	1 EC	330364.5	330364.5
	Instrumentation**	0.1 EC	33036.45	33036.45
	Sales Tax	0.03 EC	9910.934	9910.934
	Freight	0.05 EC	16518.22	16518.22
	Total Purchased Equipment Cost,	1.18 EC	389830.1	389830.1
Direct Installation Costs				
	Foundations & supports	0.08 PEC	31186.41	31186.41
	Handling & erection	0.14 PEC	54576.21	54576.21
	Electrical	0.04 PEC	15593.2	15593.2
	Piping	0.02 PEC	7796.602	7796.602
	Insulation for ductwork	0.01 PEC	3898.301	3898.301
	Painting	0.01 PEC	3898.301	3898.301
	Direct Installation Cost	0.3 PEC	116949	116949
Site preparation		As required, SP	0	0
Buildings		As required, Bldg.	0	0
	Total Direct Cost, DC	1.30 PEC + SP +	506779.1	506779.1
Indirect Costs (installation)				
	Engineering	0.1 PEC	38983.01	38983.01
	Construction and Field Expenses	0.05 PEC	19491.5	19491.5
	Contractor Fees	0.1 PEC	38983.01	38983.01
	Start-up	0.02 PEC	7796.602	7796.602
	Performance test	0.01 PEC	3898.301	3898.301
	Total Indirect Cost, IC	0.28 PEC	109152.4	109152.4
	Contingencies	0.1 DC+IC	61593.15	61593.15
	Total Capital Cost (TCC) = DC + IC +	1.61 PEC + SP +	677524.7	677524.7

Direct Annual Cost (DAC)

Fuel	Fuel	Assume		1		1820	1820
Perf. Test	Performan	Not speciated HAPs				5000	5000
Cat. Costs	Freight to return		Freight=.05*Catalyst only cost*[i/[(1+i)^n-1],			3596.76	1616.49
	Catalyst replacement		Catalyst only cost * CRFcat			88123.72	48518.32
Operating Labor							
	Operator	2 hours	Per Engine ACT-NSCR			18250	18250
	Supervisor	.15 *OL			0.15 OL	2737.5	2737.5
Maintenance							
	Labor &	.10 PEC	Per Engine ACT-		0.1 PEC	38983.01	38983.01
		Total Direct Annual Cost (DAC)				158511	116925.3
Indirect Annual Cost (IAC)							
Overhead					0.6 O&M	35982.31	35982.31
Administrative					0.02 TCC	13550.49	13550.49
Property Taxes					0.01 TCC	6775.247	6775.247
Insurance					0.01 TCC	6775.247	6775.247
Capital	for catalyst: CRFequip(TCC - 1.08(Cat only))					46965.64	46965.64
		Total Indirect Annual Cost (IAC)				110048.9	110048.9
	Total Annual Cost (TAC)					268559.9	226974.3

INPUTS AND CALCULATIONS

Model Turbine Number	13	
Turbine Exhaust Flow (lb/sec)	41	
Turbine Rating (MW)	3.5	
Turbine Rating (hp)	4,694	
Heat Input, MMBtu/hr, including	34	(Rating in MW / .29307 MW/MMBTU/hr)/ Efficiency
Hours of operation/yr	8000	
Life of equipment	15	
Life of catalyst	3 or 6 Years	
Interest rate (fraction)	0.07	
Capital Recovery Factor,	0.1098	
Capital Recovery Factor, 3-yr	0.3811	
Capital Recovery Factor, 6-yr	0.2098	
Destruction Efficiency - 3-yr & 6-yr	80	for emission reduction calculation
Destruction Efficiency - 6-yr	50	for emission reduction calculation
VAPCCI Escalator		
Fuel Type (CLEAN OR DIRTY)	CLEAN	
Turbine Assumed Efficiency	0.35	for emission reduction calculation
Turbine Exhaust Temp (0F)	1000	

Catalyst Calculations:

Vendor Estimate - Based on 80 Percent Reduction of Formaldehyde

Catalyst, Frame &	$236,584	Per Catalyst Vendors, assume housing is 30 percent of Total Catalyst Costs
Catalyst only	$165,584	EPA formula based on Vendor Quotes

Other catalyst - associated costs

Ductwork (No quantitative estimates available)

COSTS (Patterned after the OAQPS Cost Manual (1990) Thermal and Catalytic Incinerators Section)

			3-Year	6-Year Costs
Direct Costs				
Purchased Equipment Costs (PEC)				
	Catalyst + auxiliary equipment* (EC)	1 EC	$236,584	$236,584
	Instrumentation**	0.1 EC	$23,658	$23,658
	Sales Tax	0.03 EC	$7,098	$7,098
	Freight	0.05 EC	$11,829	$11,829
	Total Purchased Equipment Cost,	1.18 EC	$279,169	$279,169
Direct Installation Costs				
	Foundations & supports	0.08 PEC	$22,334	$22,334
	Handling & erection	0.14 PEC	$39,084	$39,084
	Electrical	0.04 PEC	$11,167	$11,167
	Piping	0.02 PEC	$5,583	$5,583
	Insulation for ductwork	0.01 PEC	$2,792	$2,792
	Painting	0.01 PEC	$2,792	$2,792
	Direct Installation Cost	0.3 PEC	$83,751	$83,751
Site preparation		As required, SP	$0	$0
Buildings		As required, Bldg.	$0	$0
	Total Direct Cost, DC	1.30 PEC + SP +	$362,920	$362,920
Indirect Costs (installation)				
	Engineering	0.1 PEC	$27,917	$27,917
	Construction and Field Expenses	0.05 PEC	$13,958	$13,958
	Contractor Fees	0.1 PEC	$27,917	$27,917
	Start-up	0.02 PEC	$5,583	$5,583
	Performance test	0.01 PEC	$2,792	$2,792
	Total Indirect Cost, IC	0.28 PEC	$78,167	$78,167
	Contingencies	0.1 DC+IC	$44,109	$44,109
	Total Capital Cost (TCC) = DC + IC +	1.61 PEC + SP +	$485,196	$485,196

Direct Annual Cost (DAC)

Fuel	Fuel Penalty due to	1.0			$710	$710
Perf. Test	Performance Test				$5,000	$5,000
Cat. Costs	Freight to return		Freight=.05*Catalyst only cost*[i/[(1+i)^n-1],		$2,575	$1,157
	Catalyst replacement		Catalyst only cost * CRFcat		$63,096	$34,739
Operating Labor						
	Operator	2 hours	Per Engine ACT-NSCR		$18,250	$18,250
	Supervisor	.15 *OL		0.15 OL	$2,738	$2,738
Maintenance						
	Labor &	.10 PEC	Per Engine ACT-	0.1 PEC	$27,917	$27,917
		Total Direct Annual Cost (DAC)			$120,286	$90,511

Indirect Annual Cost (IAC)

Overhead			0.6 O&M	$29,343	$29,343
Administrative			0.02 TCC	$9,704	$9,704
Property Taxes			0.01 TCC	$4,852	$4,852
Insurance			0.01 TCC	$4,852	$4,852
Capital	for catalyst: CRFequip(TCC - 1.08(Cat only))			$33,637	$33,637
		Total Indirect Annual Cost (IAC)		$82,388	$82,388
	Total Annual Cost (TAC)			$202,673	$172,898

INPUTS AND CALCULATIONS

Model Turbine Number	17	
Turbine Exhaust Flow (lb/sec)	14.2	
Turbine Rating (MW)	1.13	
Turbine Rating (hp)	1,515	
Heat Input, MMBtu/hr, including	11	(Rating in MW / .29307 MW/MMBTU/hr)/ Efficiency
Hours of operation/yr	8000	
Life of equipment	15	
Life of catalyst	3 or 6 Years	
Interest rate (fraction)	0.07	
Capital Recovery Factor,	0.1098	
Capital Recovery Factor, 3-yr	0.3811	
Capital Recovery Factor, 6-yr	0.2098	
Destruction Efficiency - 3-yr & 6-yr	80	for emission reduction calculation
Destruction Efficiency - 6-yr	50	for emission reduction calculation
VAPCCI Escalator		
Fuel Type (CLEAN OR DIRTY)	CLEAN	
Turbine Assumed Efficiency	0.35	for emission reduction calculation
Turbine Exhaust Temp (0F)	1000	

Catalyst Calculations:

Vendor Estimate - Based on 80 Percent Reduction of Formaldehyde

Catalyst, Frame &	$177,564	Per Catalyst Vendors, assume housing is 30 percent of Total Catalyst Costs
Catalyst only	$124,264	EPA formula based on Vendor Quotes

Other catalyst - associated costs

Ductwork (No quantitative estimates available)

COSTS	(Patterned after the OAQPS Cost Manual (1990) Thermal and Catalytic Incinerators Section)			
Direct Costs			3-Year	6-Year Costs
Purchased Equipment Costs (PEC)				
	Catalyst + auxiliary equipment* (EC)	1 EC	$177,564	$177,564
	Instrumentation**	0.1 EC	$17,756	$17,756
	Sales Tax	0.03 EC	$5,327	$5,327
	Freight	0.05 EC	$8,878	$8,878
	Total Purchased Equipment Cost,	1.18 EC	$209,525	$209,525
Direct Installation Costs				
	Foundations & supports	0.08 PEC	$16,762	$16,762
	Handling & erection	0.14 PEC	$29,334	$29,334
	Electrical	0.04 PEC	$8,381	$8,381
	Piping	0.02 PEC	$4,191	$4,191
	Insulation for ductwork	0.01 PEC	$2,095	$2,095
	Painting	0.01 PEC	$2,095	$2,095
	Direct Installation Cost	0.3 PEC	$62,858	$62,858
Site preparation		As required, SP	$0	$0
Buildings		As required, Bldg.	$0	$0
	Total Direct Cost, DC	1.30 PEC + SP +	$272,383	$272,383
Indirect Costs (installation)				
	Engineering	0.1 PEC	$20,953	$20,953
	Construction and Field Expenses	0.05 PEC	$10,476	$10,476
	Contractor Fees	0.1 PEC	$20,953	$20,953
	Start-up	0.02 PEC	$4,191	$4,191
	Performance test	0.01 PEC	$2,095	$2,095
	Total Indirect Cost, IC	0.28 PEC	$58,667	$58,667
	Contingencies	0.1 DC+IC	$33,105	$33,105
	Total Capital Cost (TCC) = DC + IC +	1.61 PEC + SP +	$364,154	$364,154

Direct Annual Cost (DAC)

Fuel	Fuel Penalty due to				$230	$230
Perf. Test	Performance Test				$5,000	$5,000
Cat. Costs	Freight to return		Freight=.05*Catalyst only cost*[i/[(1+i)^n-1],		$1,933	$869
	Catalyst replacement		Catalyst only cost * CRFcat		$47,351	$26,070
Operating Labor						
	Operator	2 hours	Per Engine ACT-NSCR		$18,250	$18,250
	Supervisor	.15 *OL		0.15 OL	$2,738	$2,738
Maintenance						
	Labor &	.10 PEC	Per Engine ACT-	0.1 PEC	$20,953	$20,953
		Total Direct Annual Cost (DAC)			$96,453	$74,109

Indirect Annual Cost (IAC)

Overhead			0.6 O&M	$25,164	$25,164
Administrative			0.02 TCC	$7,283	$7,283
Property Taxes			0.01 TCC	$3,642	$3,642
Insurance			0.01 TCC	$3,642	$3,642
Capital	for catalyst:	CRFequip(TCC - 1.08(Cat only))		$25,247	$25,247
		Total Indirect Annual Cost (IAC)		$64,977	$64,977
	Total Annual Cost (TAC)			$161,431	$139,086

Appendix F -- Description of SCONOx™ System

The SCONOx™ catalytic absorption system was described in a paper presented at the Power-Gen International '97 conference as follows:

> The SCONOx™ system uses a single catalyst for both CO & NOx control. It oxidizes CO to CO2 and NO to NO2, and the NO2 is then absorbed onto the surface of the catalyst. Just as a sponge absorbs water and must be wrung out periodically, the SCONOx™ catalyst must be periodically regenerated. This is accomplished by passing a dilute hydrogen gas across the surface of the catalyst in the absence of oxygen. Nitrogen oxides are broken down into nitrogen and water, and this is exhausted up the stack instead of NOx.

Source: "The SCONOx™ Catalytic Absorption system for Natural Gas Fired Power Plants: The Path to Ultra-Low Emissions," Robert J. MacDonald, P.E., and Lawrence Debbage, presented to Power-Gen International '97, December 9-11, 1997.

Appendix G -- Cost-Effectiveness for Individual HAPs

Model 1 -- 85.4 MW Turbine

Pollutant	80% Reduction & 3-Yr Catalyst Life		80% Reduction & 6-Yr Catalyst Life		50% Reduction & 6-Yr Catalyst Life	
	Highest EF	Average EF	Highest EF	Average EF	Highest EF	Average EF
Formaldehyde	$85,213	$670,472	$70,432	$554,173	$112,692	$886,677
Toluene	$629,008	$3,366,524	$519,902	$2,782,575	$831,843	$4,452,120
Acetaldehyde	$1,365,847	$5,241,737	$1,128,930	$4,332,518	$1,806,289	$6,932,029
Xylenes	$3,983,720	$10,414,955	$3,292,714	$8,608,402	$5,268,342	$13,773,443
Ethylbenzene	$11,659,669	$11,659,669	$9,637,211	$9,637,211	$15,419,538	$15,419,538
Benzene	$12,226,251	$46,412,275	$10,105,515	$38,361,714	$16,168,825	$61,378,743
PAHs	$65,306,889	$214,370,595	$53,978,915	$177,186,393	$86,366,264	$283,498,228
Acrolein	$78,626,057	$87,075,852	$64,987,772	$71,971,886	$103,980,436	$115,155,018
Naphthalene	$144,424,903	$327,429,060	$119,373,310	$270,634,011	$190,997,296	$433,014,417
Total HAPs	$68,914	$454,166	$56,961	$375,388	$91,137	$600,620

Model 2 -- 170 MW Turbine

Pollutant	80% Reduction & 3-Yr Catalyst Life		80% Reduction & 6-Yr Catalyst Life		50% Reduction & 6-Yr Catalyst Life	
	Highest EF	Average EF	Highest EF	Average EF	Highest EF	Average EF
Formaldehyde	$61,887	$486,938	$51,100	$402,062	$81,760	$643,299
Toluene	$456,825	$2,444,978	$377,198	$2,018,804	$603,516	$3,230,087
Acetaldehyde	$991,963	$3,806,874	$819,058	$3,143,314	$1,310,492	$5,029,302
Xylenes	$2,893,224	$7,563,985	$2,388,918	$6,245,538	$3,822,269	$9,992,861
Ethylbenzene	$8,467,973	$8,467,973	$6,991,956	$6,991,956	$11,187,129	$11,187,129
Benzene	$8,879,461	$33,707,467	$7,331,718	$27,832,058	$11,730,750	$44,531,292
PAHs	$47,429,906	$155,689,197	$39,162,595	$128,551,656	$62,660,151	$205,682,649
Acrolein	$57,103,110	$63,239,874	$47,149,703	$52,216,793	$75,439,524	$83,546,868
Naphthalene	$104,890,305	$237,799,252	$86,607,309	$196,349,447	$138,571,694	$314,159,115
Total HAPs	$50,050	$329,844	$41,326	$272,350	$66,122	$435,760

Model 7 -- 39.6 MW Turbine

Pollutant	80% Reduction & 3-Yr Catalyst Life		80% Reduction & 6-Yr Catalyst Life		50% Reduction & 6-Yr Catalyst Life	
	Highest EF	Average EF	Highest EF	Average EF	Highest EF	Average EF
Formaldehyde	$100,204	$788,418	$83,289	$655,330	$133,262	$1,048,528
Toluene	$739,661	$3,958,748	$614,803	$3,290,496	$983,685	$5,264,793
Acetaldehyde	$1,606,121	$6,163,841	$1,335,001	$5,123,360	$2,136,002	$8,197,375
Xylenes	$4,684,519	$12,247,109	$3,893,753	$10,179,747	$6,230,005	$16,287,596
Ethylbenzene	$13,710,787	$13,710,787	$11,396,351	$11,396,351	$18,234,162	$18,234,162
Benzene	$14,377,040	$54,576,921	$11,950,138	$45,364,117	$19,120,221	$72,582,586
PAHs	$76,795,394	$252,081,741	$63,832,022	$209,529,327	$102,131,235	$335,246,924
Acrolein	$92,457,612	$102,393,858	$76,850,395	$85,109,363	$122,960,632	$136,174,980
Naphthalene	$169,831,505	$385,028,960	$141,163,263	$320,034,521	$225,861,221	$512,055,233
Total HAPs	$81,038	$534,061	$67,358	$443,910	$107,773	$710,255

Model 9 -- 27 MW Turbine

Pollutant	80% Reduction & 3-Yr Catalyst Life		80% Reduction & 6-Yr Catalyst Life		50% Reduction & 6-Yr Catalyst Life	
	Highest EF	Average EF	Highest EF	Average EF	Highest EF	Average EF
Formaldehyde	$96,796	$761,608	$81,023	$637,504	$129,637	$1,020,007
Toluene	$714,509	$3,824,133	$598,080	$3,200,990	$956,927	$5,121,583
Acetaldehyde	$1,551,505	$5,954,241	$1,298,687	$4,983,997	$2,077,900	$7,974,395
Xylenes	$4,525,223	$11,830,650	$3,787,838	$9,902,844	$6,060,540	$15,844,550
Ethylbenzene	$13,244,556	$13,244,556	$11,086,354	$11,086,354	$17,738,167	$17,738,167
Benzene	$13,888,154	$52,721,050	$11,625,077	$44,130,148	$18,600,124	$70,608,237
PAHs	$74,183,991	$243,509,783	$62,095,700	$203,829,832	$99,353,120	$326,127,732
Acrolein	$89,313,621	$98,911,988	$74,759,955	$82,794,267	$119,615,928	$132,470,827
Naphthalene	$164,056,440	$371,936,175	$137,323,422	$311,329,127	$219,717,475	$498,126,604
Total HAPs	$78,282	$515,901	$65,526	$431,835	$104,841	$690,935

Model 13 -- 3.5 MW Turbine

Pollutant	80% Reduction & 3-Yr Catalyst Life		80% Reduction & 6-Yr Catalyst Life		50% Reduction & 6-Yr Catalyst Life	
	Highest EF	Average EF	Highest EF	Average EF	Highest EF	Average EF
Formaldehyde	$363,955	$2,863,658	$310,486	$2,442,953	$496,777	$3,908,725
Toluene	$2,686,563	$14,378,788	$2,291,876	$12,266,378	$3,667,001	$19,626,205
Acetaldehyde	$5,833,680	$22,388,026	$4,976,645	$19,098,966	$7,962,632	$30,558,345
Xylenes	$17,014,900	$44,483,398	$14,515,214	$37,948,271	$23,224,342	$60,717,234
Ethylbenzene	$49,799,706	$49,799,706	$42,483,553	$42,483,553	$67,973,684	$67,973,684
Benzene	$52,219,641	$198,231,840	$44,547,971	$169,109,287	$71,276,753	$270,574,860
PAHs	$278,932,781	$915,599,980	$237,954,325	$781,087,739	$380,726,920	$1,249,740,383
Acrolein	$335,820,387	$371,910,374	$286,484,483	$317,272,433	$458,375,173	$507,635,893
Naphthalene	$616,854,367	$1,398,484,901	$526,231,317	$1,193,031,273	$841,970,107	$1,908,850,037
Total HAPs	$294,341	$1,939,794	$251,099	$1,654,815	$401,758	$2,647,705

Model 15 -- 9 MW Turbine

Pollutant	80% Reduction & 3-Yr Catalyst Life		80% Reduction & 6-Yr Catalyst Life		50% Reduction & 6-Yr Catalyst Life	
	Highest EF	Average EF	Highest EF	Average EF	Highest EF	Average EF
Formaldehyde	$187,550	$1,475,677	$158,509	$1,247,173	$253,614	$1,995,477
Toluene	$1,384,418	$7,409,561	$1,170,045	$6,262,213	$1,872,072	$10,019,541
Acetaldehyde	$3,006,165	$11,536,816	$2,540,669	$9,750,376	$4,065,071	$15,600,602
Xylenes	$8,767,980	$22,922,824	$7,410,286	$19,373,296	$11,856,457	$30,997,274
Ethylbenzene	$25,662,381	$25,662,381	$21,688,641	$21,688,641	$34,701,826	$34,701,826
Benzene	$26,909,402	$102,151,226	$22,742,565	$86,333,426	$36,388,104	$138,133,482
PAHs	$143,737,381	$471,819,563	$121,480,094	$398,759,771	$194,368,151	$638,015,633
Acrolein	$173,052,241	$191,649,841	$146,255,640	$161,973,459	$234,009,023	$259,157,534
Naphthalene	$317,872,394	$720,655,908	$268,650,843	$609,064,582	$429,841,348	$974,503,331
Total HAPs	$151,677	$999,599	$128,191	$844,814	$205,105	$1,351,702

Model 17 -- 1.13 MW Turbine

Pollutant	80% Reduction & 3-Yr Catalyst Life		80% Reduction & 6-Yr Catalyst Life		50% Reduction & 6-Yr Catalyst Life	
	Highest EF	Average EF	Highest EF	Average EF	Highest EF	Average EF
Formaldehyde	$897,899	$7,064,815	$773,614	$6,086,919	$1,237,782	$9,739,070
Toluene	$6,627,912	$35,473,330	$5,710,491	$30,563,190	$9,136,785	$48,901,104
Acetaldehyde	$14,392,037	$55,232,597	$12,399,923	$47,587,423	$19,839,877	$76,139,877
Xylenes	$41,976,774	$109,743,200	$36,166,442	$94,552,789	$57,866,307	$151,284,462
Ethylbenzene	$122,858,851	$122,858,851	$105,853,000	$105,853,000	$169,364,800	$169,364,800
Benzene	$128,828,974	$489,049,793	$110,996,752	$421,356,601	$177,594,803	$674,170,562
PAHs	$688,143,835	$2,258,839,853	$592,892,485	$1,946,176,230	$948,627,977	$3,113,881,969
Acrolein	$828,488,959	$917,525,113	$713,811,348	$790,523,314	$1,142,098,156	$1,264,837,302
Naphthalene	$1,521,816,578	$3,450,145,803	$1,311,170,089	$2,972,584,242	$2,097,872,142	$4,756,134,788
Total HAPs	$726,157	$4,785,587	$625,644	$4,123,176	$1,001,030	$6,597,082

Attachment 11

Interpreting and Using Emissions Databases Containing Non-Detection Values (Closure Item)

TMPWG Guidance Document On Interpreting and Using Emissions Databases Containing Non-detection Values

The ICCR Testing and Monitoring Protocols Workgroup (TMPWG) reviewed ICCR issues which result from emission testing that produce reports of non-detection concentrations and we formulated procedures and recommendations to deal with such reports. With existing EPA ICCR and other databases, we assumed that there is a need to obtain mean and/or median values and variability for data sets for various reasons. The most critical reason might be determining whether a toxic emission from a group of potential emissions sources warrants further consideration in the ICCR process.

We believe that any decision to control HAP emissions from combustion sources should be made on the basis of fuel composition, combustion science, and actual observations. No decisions leading to the imposition of control devices or emission limits on combustion processes should be made that are based on emission levels derived from default HAP concentrations calculated from method detection levels.

We strongly encourage all Source Work Groups (SWG) to define a "critical concentration level" below which HAP emissions are not significant for the purposes of data gathering as part their planning future emissions testing related to the ICCR process. The TMPWG would be available to assist in designing a test protocol to reach that goal.

Our recommendation is for the SWG to follow these steps when making decisions that involve interpretation of databases with reported non-detection reports for some pollutants:

Step 1: In addition to emission concentration levels, consider fuel composition, scientific and engineering data to focus efforts towards HAP emissions that are potentially significant. Doing this is critical for non-detection and other issues because it is impractical and simply not necessary to solely rely on stack testing to rule out all 189 chemicals that appear on the EPA toxics substances list. Material balances using fuel composition and consumption rates along with published flame chemistry science are most useful in this regard. We believe that most potential non-detection issues can best be circumvented by completion of Step 1.

Step 2: Associate detection limits with individual source tests that resulted in non-detection reports either by retrieving the detection limit from the database, or assigning conservative detection limits based on the descriptions of the measurement procedures. Retrieval is preferred, but assignments without uncertainties are not realistic.

Step 3: Assume that the actual concentrations could be as high as the detection limits to determine if the emissions have the potential to be important in the ICCR process even with the highest potential concentration. If the answer is no, there is no need for the following steps.

Step 4: Create a data subset which contains only those source measurements that have the lowest detection limits, and repeat Step 3 If the answer becomes no, and if the reviewers agree that the subset is representative of the industry emissions sources, there is no need for the following steps.

Step 5: Define the detection level that is needed to resolve the ICCR issues relative to the emission of a specific HAP, this sets a "critical concentration level" below which emissions are not significant for the most restrictive ICCR issues.

Step 6: The best course of action for filling data gaps is the collection of data using methodology with the appropriately low detection limits. A less desirable alternative is to use the ½ detection limit substitution method on an existing database.

The publications by Helsel[6], Coleman, *et. al*[7]., and Zorn *et. al*.[8] address the issues of dealing with databases that contain a mixture of detection and non-detection values, and give procedures for determining mean and median values. Procedures that are discussed and provided range from simple substitution to complex statistical methods. The publications show mean and median values can be generated with the highest certainty when:

1. The detection limits for each measurement is known with certainty, and when the detection limit and the definition of the detection limit are consistent.
2. The ratio of non-detection to detection values is less than 1, and when there are enough detectable values so the mean and median values are not dominated by statistical outliers.

Simple substitution methods using the ½ detection limits generally perform poorly as compared to the more complex statistical methodology when the above conditions were met. Substitution of zero for the detection limit was discouraged because it will result in a low bias, and substitution of the detection limit was discouraged because it will result in a high bias. We believe that limitations in the existing database make the ½ detection limits substitution method the most applicable for working with existing databases. But testing with appropriate detection limits is the most reliable approach and is our first recommendation for filling data gaps.

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[1] Dennis R. Helsel, “Less than obvious: statistical treatment of data below the detection limit”, Environ. Sci. Technol., 1990, Vol. 24, pp. 1766 - 1774.

[2] David Coleman, *et.al.*, “Regulation between detection limits, quantification limits, and significant digits” Chemometics and Intelligent Laboratory Systems, 1997, Vol. 37, pp 71-80.

[8] Michael E. Zorn, *et. al.*, “Weighted least-squares approach to calculating limits of detection and quantification by modeling variability as a function of concentration”, Anal. Chem., 1997, Vol. 69, pp. 3069-3075.

Attachment 12

RICE Work Group Presentation on Rich Burn Engine Definition

Item for Closure:

Definition of "Rich Burn Engine" for the Reciprocating Internal Combustion Engine (RICE) MACT Standard

presented to:

ICCR Coordinating Committee
Durham, North Carolina

presented by:

Sam Clowney, Tennessee Gas Pipeline
on behalf of the RICE Work Group

September 16, 1998

Summary

- RICE WG has not reached consensus on the appropriate regulatory definition for “rich burn engines”
- Paper developed to document the Work Group’s discussions regarding the regulatory definition for “rich burn engines”
- WG recommends that the Coordinating Committee forward the information presented in the paper to EPA as a recommendation so that EPA will consider the information in developing the regulatory definition of “rich burn engines”

Background on Rich & Lean Burn

- Spark-ignition engines may run either rich or lean of stoichiometry, depending on engine design and setpoints for fuel flow and intake air
  - Stoichiometry is a precise point - chemically correct air-to-fuel ratio that would be required for complete combustion
  - Rich of stoichiometry refers to operation at any air-to-fuel ratio less than stoichiometry
  - Lean of stoichiometry refers to operation at any air-to-fuel ratio greater than stoichiometry
- Traditionally, rich burn engines have included engines that run slightly lean of stoichiometry -- lean limit for rich burn engines varies

Need for Definition (1)

- Natural gas-fired engines subcategorized based on whether 2-stroke or 4-stroke, rich or lean burn
- Natural gas-fired engines subcategorized further than engines using other fuels:
  - to reflect the engineering differences between 2-stroke and 4-stroke, rich-burn and lean-burn engines
  - to reflect the fact that there are two prevalent control devices in the existing population that involve oxidation -- a 3-way catalyst, known as non-selective catalytic reduction (NSCR), and oxidation catalysts -- NSCR is mostly used on rich burn engines and oxidation catalysts are mostly used on lean burn engines for criteria pollutant control

Need for Definition (2)

- For MACT floor analysis, 4-stroke natural gas-fired engines designated SI-NG-4SLB or SI-NG-4SRB based on the manufacturer’s designation of the engine model as a “rich burn” or a “lean burn”
- As a result of analysis, RICE WG determined that the MACT floor for SI-NG-4SRB engines should be based on NSCR -- for other subcategories, RICE WG determined there was no MACT floor
- MACT Floor rationale presented to CC in July 1998 -- does not include a definition of “rich burn engine”

Approach to Definition

Since July 1998, WG has discussed approach & possible lean limits for the "rich burn" definition:

- Approach: Base definition on technical characteristics
  - air-to-fuel ratio (AFR);
  - lambda (AFR divided by stoichiometric AFR ratio);
  - exhaust oxygen content; or
  - manufacturer's designation of the engine as "rich burn"
- Possible lean limits for "rich burn engines"
  - only those engines that can use NSCR as a 3-way catalyst for the simultaneous reduction of NOx, CO, and HC; or
  - engines beyond those that may use NSCR as a 3-way catalyst, so long as all "rich burn engines" could meet the MACT requirements for the SI-NG-4SRB subcategory through the use of any device, such as an oxidation catalyst or an NSCR used solely for oxidation

Definitions Discussed (1)

- WG has discussed 6 types of definitions, based on:
  - manufacturer's designation as "rich burn"
  - ability to use NSCR on the engine
  - air-to-fuel ratio (AFR) slightly lean of stoichiometric
  - lambda 1.1 (AFR divided by stoichiometric AFR)
  - exhaust oxygen content of 4% or less
  - exhaust oxygen content of 1% or less
- WG identified pros and cons for each definition
- WG identified instances where definition has been used previously (for criteria pollutants)

Definitions Discussed (2)

1 Rich burn means engines that are designated 'rich-burn' by the manufacturer based on the design of the engine model when manufactured.

2 Rich burn means engines that can use non-selective catalytic reduction control technology.

3 Rich burn means an engine with an air-to-fuel ratio (AFR) operating range that is near to stoichiometric or fuel-rich of stoichiometric and can be adjusted to operate with an exhaust oxygen concentration of 1 percent or less.

Definitions Discussed (3)

4a Rich burn engine means a two stroke or four-stroke spark-ignited engine where the manufacturer's original recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio is less than or equal to 1.1.

4b Rich burn engine means a two stroke or four-stroke spark-ignited engine where the operating air/fuel ratio divided by the stoichiometric air/fuel ratio is less than or equal to 1.1.

5 Rich burn means a four-stroke, spark-ignited engine where the oxygen content in the exhaust stream before any dilution is 4% or less measured on a dry basis.

6 Rich burn means a four-stroke, spark-ignited engine where the oxygen content in the exhaust stream before any dilution is 1% or less measured on a dry basis.

Conclusions (1)

- WG has not agreed on regulatory definition -- views may be summarized as follows:
  - Technical characteristics:
    - » exhaust oxygen content should be used because it is easy to measure & determine precisely in the field; or
    - » lambda 1.1 should be used because it is technically precise
  - Extent of the category:
    - » limit to engines that can use NSCR as a 3-way catalyst; or
    - » extend to other engines -- so long as all engines included could meet the MACT requirements through the use of any device
  - Preventing temporary adjustment to avoid rich burn status:
    - » link definition to manufacturer's specifications for model; or
    - » do not rely solely on manufacturer's specifications -- accommodate re-manufacture or re-construction of engine & diverse operating conditions

Conclusions (2)

- WG does agree on the goals for the definition of "rich burn engines":
  - The definition should incorporate engines that operate both fuel-rich and slightly lean of stoichiometry
  - The definition should incorporate other engines only where the control needed to meet the MACT regulation is achievable
  - The definition should recognize that existing engines, originally considered "rich burn" might have been modified in the field to run at conditions that are significantly lean of stoichiometry
  - The definition should not allow engine owners and operators the opportunity to adjust the engine to lean burn status to avoid rich burn regulatory requirements

Recommendation to CC

- RICE WG recommends that the CC forward the materials developed by the WG to EPA as a recommendation:
  - Although RICE WG has not reached consensus on the appropriate regulatory definition for "rich burn engines," the WG has reached consensus on the goals the definition should achieve
  - Paper provides important information to EPA on the possible definitions for "rich burn engines" and documents the WG views on the pros and cons for each definition considered

Attachment 13

Paper on Rich Burn Engine Definition
(Closure Item)

Definition of "Rich Burn Engine" for the Reciprocating Internal Combustion Engine (RICE) MACT Standard

Prepared for:
Coordinating Committee of the
Industrial Combustion Coordinated Rulemaking (ICCR)

Prepared by:
Reciprocating Internal Combustion Engine Work Group
Of the Industrial Combustion Coordinated Rulemaking

September 4, 1998

TABLE OF CONTENTS

1.0 INTRODUCTION

This paper documents the discussions that occurred within the Reciprocating Internal Combustion Engine (RICE) Work Group regarding a regulatory definition for "rich burn engines." Stationary RICE operate with various air-to-fuel ratios and, in general, may be classified as either rich or lean of stoichiometry. Stoichiometry is a precise point that may be defined as the chemically correct air-to-fuel ratio that would be required for complete combustion. Rich of stoichiometry refers to fuel-rich combustion, i.e., operation at any air-to-fuel ratio less than stoichiometry. Lean of stoichiometry refers to fuel-lean combustion, i.e., operation at any air-to-fuel ratio numerically higher than stoichiometry. All compression-ignition engines run lean of stoichiometry. Spark-ignition engines may run either rich or lean of stoichiometry, depending on engine design and setpoints for fuel flow and intake air.

The Work Group agreed by consensus that there should be a subcategory for Spark-Ignition, Natural Gas, 4-Stroke, Rich Burn engines (SI-NG-4SRB). However, the Work Group has not reached consensus on the appropriate regulatory definition for the RICE MACT standard to best distinguish engines in that subcategory from engines that would be included in the Spark-Ignition, Natural Gas, 4-Stroke, Lean Burn (SI-NG-4SLB) subcategory. The Work Group developed this paper to document the Work Group's discussions of this issue. The Work Group recommends that the Coordinating Committee forward the information presented in this paper to EPA as a recommendation so that EPA will consider the information in developing the regulatory definition of "rich burn engines" for the RICE MACT standard.

The need for a definition of rich burn in the context of the RICE MACT standard is discussed below, along with a list of the definitions discussed to date by the RICE Work Group. Sections II through VII provide a record of the definitions considered by the Work Group to date, the instances where these definitions have been used previously, and the Work Group views on the pros and cons of the use of the definitions for the RICE MACT standard.

The final section of this paper presents the Work Group's conclusions and recommendations to the Coordinating Committee regarding the definition of "rich burn engine".

A. Need for a Definition of "Rich Burn Engine" for the RICE MACT Standard

As indicated above, the need for a regulatory definition of "rich burn engine" arose out of the need to distinguish those engines that would be included in the SI-NG-4SRB subcategory from those engines that would be included in the SI-NG-4SLB subcategory for the RICE MACT standard.

For existing engines, the RICE Work Group identified ten subcategories:

- Spark-Ignition, Natural Gas 4-Stroke Rich Burn Engines
- Spark-Ignition, Natural Gas 4-Stroke Lean Burn Engines
- Spark-Ignition, Natural Gas 2-Stroke Lean Burn Engines
- Spark-Ignition, Digester Gas and Landfill Gas Engines
- Spark-Ignition, Propane, Liquid Petroleum Gas (LPG), and Process Gas Engines
- Spark-Ignition, Gasoline Engines
- Compression-Ignition, Liquid Fuel Engines (diesel, residual/crude oil, kerosene/naphtha)
- Compression-Ignition, Dual Fuel Engines
- Emergency Power Units
- Small Engines (200 brake horsepower or less)

Engines included in the Emergency Power Units subcategory were identified by the engine's use on an emergency basis. Engines in the Small Engines subcategory were identified by size (engines 200 brake horsepower or less). For engines that were not considered emergency power units or small engines, the RICE Work Group subcategorized the engines by whether the engines were spark-ignited or compression-ignited and by fuel type. For natural gas, the Work Group also subcategorized engines based on whether the engines were 2-stroke and 4-stroke engines and whether the engines were lean burn engines or rich burn engines.

The natural gas-fired engines were subcategorized further than engines using fuels other than natural gas for the following reasons:

- To reflect the engineering differences between 2-stroke and 4-stroke, rich-burn and lean-burn engines, and

- To reflect the fact that there are two most prevalent control devices in the existing population of engines that involve oxidation -- a 3-way catalyst, known as non-selective catalytic reduction (NSCR), and oxidation catalysts -- NSCR is mostly used on "rich burn engines" and oxidation catalysts are mostly used on "lean burn" engines for criteria pollutant control.[9]

Therefore, the RICE Work Group concluded that it was necessary to further subcategorize natural gas-fired engines. For the MACT floor analysis, 4-stroke natural gas-fired engines included in the ICCR Population Database were designated as SI-NG-4SLB or SI-NG-4SRB based on the manufacturer's designation of the engine model as a "rich burn engine" or a "lean burn engine." As a result of this analysis, the Work Group determined that the MACT floor for SI-NG-4SRB engines should be based on NSCR. For engines in all subcategories other than SI-NG-4SRB, the Work Group concluded that no MACT floor could be identified and therefore there was no MACT floor for those subcategories.

The Work Group presented its recommendations on subcategories and MACT floors to the ICCR Coordinating Committee at the July 1998 meeting. The ICCR Coordinating Committee agreed with the findings of the RICE Work Group regarding subcategories and MACT floor and on August 12, 1998, the Committee forwarded the “Recommended Subcategories and MACT Floors for Existing Stationary Reciprocating Internal Combustion Engines (RICE),” (MACT Floor Rationale) to EPA. The MACT Floor Rationale recommended to EPA that the MACT floor for SI-NG-4SRB engines should be based on the use of NSCR control technology. For

[9] Based on a review of available information, the Work Group had determined that add-on control devices that involve oxidation are most applicable for HAPs reduction from RICE. NSCR is a 3-way catalyst system that simultaneously controls nitrogen oxides (NOx), carbon monoxide (CO), and hydrocarbons (HC). With regards to NSCR, the Work Group concluded that NSCR catalysts do involve oxidation and would exhibit some effectiveness in oxidizing formaldehyde and other similar HAPs.

engines in all other subcategories, MACT Floor Rationale recommended that there is no MACT floor.

Although the designation of an engine as "rich burn" by the manufacturer was used to analyze data in the ICCR Population Database to determine the MACT floor, the MACT Floor Rationale forwarded to EPA by the Coordinating Committee does not include a definition for the SI-NG-4SRB subcategory or for "rich burn engines." In Section 1.1.2.3 of the MACT Floor Rationale, it is noted that a common method used to distinguish between “rich burn” and “lean burn” engines is the percentage oxygen in the exhaust stream. The Rationale also indicates that several regulatory agencies have adopted a value of 4 percent oxygen in the exhaust as the defining limit for “rich burn” engines. The RICE Work Group has agreed that the information in Section 1.1.2.3 does not constitute a definition of “rich burn engines” for the RICE MACT standard. Rather, the facts were included as information to describe some of the current practices.

Since the July 1998 Coordinating Committee, the RICE Work Group has held a number of discussions regarding the appropriate approach to establish a regulatory definition of “rich burn engine” for the purposes of the RICE MACT standard. Some of the RICE Work Group members believe that the regulatory definition of "rich burn engines" should be based on technical characteristics of the engine. The Work Group members have not agreed on the specific technical characteristics that should be used to define "rich burn engines." Possible technical characteristics that have been discussed for the definition of "rich burn engines" include air-to-fuel ratio, lambda (air-to-fuel ratio divided by stoichiometric air-to-fuel ratio), exhaust oxygen content, and the manufacturer's designation of the engine as "rich burn." The Work Group members also have not agreed on the limits of the SI-NG-4SRB subcategory. Some Work Group members believed the subcategory should include only those engines that can use NSCR as a 3-way catalyst for the simultaneous reduction of NOx, CO, and HC. Other Work Group members believed that "rich burn engines" should include engines beyond those that may use NSCR as a 3-way catalyst, so long as all "rich burn engines" could meet the MACT requirements for the SI-NG-4SRB subcategory through the use of any device, such as an oxidation catalyst or an NSCR used solely for oxidation.

The possible definitions discussed to date are listed in the following section.

B. Definitions of Rich Burn Discussed by the RICE Work Group

The RICE Work Group has discussed the following definitions of “rich burn engine”:

- "Rich burn means engines that are designated as ‘rich-burn’ by the manufacturer based on the design of the engine model when manufactured.”
- "Rich burn means engines that can use non-selective catalytic reduction control technology.”
- "Rich burn means an engine with an air-to-fuel ratio (A/F) operating range that is near to stoichiometric or fuel-rich of stoichiometric and can be adjusted to operate with an exhaust oxygen concentration of 1 percent or less."
- "Rich burn engine means a two stroke or four-stroke spark-ignited engine where the manufacturer’s original recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio is less than or equal to 1.1.”
- "Rich burn engine means a two stroke or four-stroke spark-ignited engine where the operating air/fuel ratio divided by the stoichiometric air/fuel ratio is less than or equal to 1.1.”
- "Rich burn means a four-stroke, spark-ignited engine where the oxygen content in the exhaust stream before any dilution is 4% or less measured on a dry basis."
- "Rich burn means a four-stroke, spark-ignited engine where the oxygen content in the exhaust stream before any dilution is 1% or less measured on a dry basis."

Discussion of these definitions is provided below.

II. DEFINE AS ENGINES DESIGNATED RICH BURN BY THE MANUFACTURER

Definition Discussed by the Work Group:

"Rich burn means engines that are designated as 'rich-burn' by the manufacturer based on the design of the engine model when manufactured."

Pros:

- Definition is consistent with the methodology used to designate engines as "rich burn" in the ICCR Population Database. The engines designated as "rich burn" were used to determine the MACT floor for the SI-NG-4SRB subcategory.

- Since the definition relies on the manufacturer's original designation of the engine as a rich burn, owners or operators do not have the opportunity to adjust the engine to lean-burn status to avoid rich-burn regulatory requirements.

  [Note: For NOx, regulators were very concerned about this possibility since there were higher NOx emission limitations for lean-burn engines, which relied on different control technologies to reduce NOx. For the RICE MACT standard, similar oxidation control technologies have been identified for both rich burn and lean burn engines. However, it is unclear whether the MACT standard for SI-NG-4SRB engines will be the same or nearly the same as the MACT standard for SI-NG-4SLB engines.]

Cons:

- The definition of "rich burn engine" would be based solely on the manufacturer designation and there is not a definite cutpoint for rich burn that has been used consistently for all engine manufacturers. However, since engines with air/fuel ratios of around 16:1 are designated "rich burn" by manufacturers and engines with air/fuel ratios no less than 24:1 are designated "lean-burn," this should not be a significant problem.

- The definition relies on the designation specified by the manufacturer at the time of manufacture. The definition does not accommodate the re-manufacture and re-construction of existing engines which may result in conversions of engines originally specified as "rich burn" to operate significantly lean of stoichiometric conditions. The modified engines may have engineering and operating characteristics more closely akin to lean burn engines than to rich burn engines.

- Many rich-burn engines operate slightly lean of stoichiometric conditions. For those engines, the exhaust oxygen concentration may be higher than the level required to use NSCR controls as intended for NOx control. In order to use NSCR as intended for

NOx control, it would be necessary to adjust the engine to run at 1 percent oxygen or less. However, engines may be able to use other devices to comply with MACT.

- In most cases, operators who install NSCR use an air-to-fuel ratio controller to maintain the proper air-to-fuel ratio and exhaust gas oxygen content required to use NSCR technology as intended for NOx control. However, for some older models of engines, commercially available air-to-fuel ratio controllers cannot ensure that the engines will operate with exhaust concentrations of 1 percent oxygen or less, at all load conditions, including low-loads.

Instances Where the Definition Has Been Used Previously:

- NONE

III. Define as Engines that Can Use Non-Selective Catalytic Reduction

Definition Discussed by the Work Group:

"Rich burn means engines that can use non-selective catalytic reduction control technology."

Pros:

- Limits "rich burn engines" to only those engines that can use NSCR. With this definition, NSCR would be achievable for all engines in the subcategory.

Cons:

- The definition of "rich burn engine" would be based solely on a control technology, not the engineering characteristics of the engine.

- "Can use NSCR" is not a precise, measurable characteristic. To be covered under this definition, an engine must be able to be operated with NSCR as intended for NOx control. To avoid being covered under this definition, source owners and operators would need to demonstrate to permitting/ enforcement personnel that the engine cannot be operated with NSCR. [Note: In the latter case, the engine would be covered under requirements for lean burn engines.]

Instances Where the Definition Has Been Used Previously:

- NONE

IV. Define as Engines Near to Stoichiometric or Fuel-Rich of Stoichiometric

Definition Discussed by the Work Group:

> "Rich burn means an engine with an air-to-fuel ratio (A/F) operating range that is near to stoichiometric or fuel-rich of stoichiometric and can be adjusted to operate with an exhaust oxygen concentration of 1 percent or less."

<u>Pros:</u>

- Fuel-rich of stoichiometric is a precise, measurable point.

- Limits "rich burn engines" to only those engines that can be adjusted to operate with an exhaust oxygen concentration that is compatible with the use of NSCR as intended for NOx control. With this definition, NSCR would function as intended for NOx control on all "rich burn engines".

- Definition reflects the operating conditions of the engine, not simply the conditions specified by the manufacturer. Therefore, the definition accommodates diverse operating conditions of existing engines, which may result in higher exhaust oxygen content than the levels specified by the design of the engine manufacturer.

- Definition takes into account the possible re-manufacture or re-construction of an existing engine, which may result in an exhaust gas oxygen content different than that specified by the manufacturer.

<u>Cons:</u>

- Near to stoichiometric is not a precise, measurable point. Under this definition, for engines operating fuel-lean of stoichiometric, it would be necessary for source owners and operators to demonstrate to permitting/enforcement personnel that the engine could not be operated with an exhaust oxygen concentration of 1 percent or less.

- Since near to stoichiometric is not a precise point, it is unclear whether engines operating slightly lean of stoichiometric are included. Engine manufacturers do include engines slightly lean of stoichiometric as "rich burn."

- To determine whether an engine is covered under this definition, it is necessary to know the stoichiometric air-to-fuel ratio for the fuel being used, along with the operating air-to-fuel ratio. To determine operating air-to-fuel ratio, engine operators need to measure at least the oxygen content of the exhaust.

- The definition relies on air-to-fuel ratio, which is difficult to precisely measure in the field.

Instances Where the Definition Has Been Used Previously:

- The EPA Alternative Control Techniques Document for Nitrogen Oxide Emissions from Stationary Reciprocating Internal Combustion Engines uses this definition:

  "A rich-burn engine is classified as one with an air-to-fuel ratio (A/F) operating range that is near stoichiometric or fuel-rich of stoichiometric and can be adjusted to operate with an exhaust oxygen concentration of 1 percent or less."

V. DEFINE AS ENGINES WHERE THE AIR-TO-FUEL RATIO DIVIDED BY STOICHIOMETRIC AIR-TO-FUEL RATIO (LAMBDA) IS 1.1 OR LESS

Definition Discussed by the Work Group:

> "Rich burn engine means a two stroke or four-stroke spark-ignited engine where the manufacturer's original recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio is less than or equal to 1.1."
>
> and
>
> "Rich burn engine means a two stroke or four-stroke spark-ignited engine where the operating air/fuel ratio divided by the stoichiometric air/fuel ratio is less than or equal to 1.1."

Pros:

- A lambda target, such as 1.1, is independent of fuel, whereas air-to-fuel ratio alone would be fuel dependent.
- Lambda 1.1 is a technically precise point, making compliance determinations definitive.
- If the definition relies on the manufacturer's original recommended air-to-fuel ratio, owners or operators do not have the opportunity to adjust the engine to lean-burn status to avoid rich burn regulatory requirements.
- To determine operating air-to-fuel ratio, engine operators can measure the oxygen content of the exhaust.

Cons:

- Lambda is more difficult to measure/calculate than exhaust oxygen levels. Two air-to-fuel ratios are necessary to determine lambda: the stoichiometric air-to-fuel ratio and either the manufacturer's recommended air-to-fuel ratio or the operating air-to-fuel ratio. The manufacturer's recommended air-to-fuel ratio may be difficult to determine for older engines. Where fuel composition changes significantly, the stoichiometric air-to-fuel ratio may be difficult to determine, since it is dependent on fuel composition. The operating air-to-fuel ratio is difficult to precisely measure in the field.

- If the definition relies on the air-to-fuel ratio originally specified by the engine manufacturer, the definition does not accommodate the diverse operating conditions of existing engines and the re-manufacture and re-construction of existing engines which may result in different air-to-fuel ratios than those specified by the design of the engine manufacturer.

- If the definition relies on lambda calculated with the current operating air-to-fuel ratio (not the manufacturer's specifications), owners and operators would have the opportunity to adjust the air-to-fuel ratio to raise lambda and thereby qualify the engine as a "lean burn engine." The definition does not incorporate sufficient constraints to prohibit engine owners and operators from temporarily adjusting the engine to avoid rich burn regulatory requirements.

  [Note: For NOx, regulators were very concerned about this possibility since there were higher NOx emission limitations for lean-burn engines, which relied on different control technologies to reduce NOx. For the RICE MACT standard, similar oxidation control technologies have been identified for both rich burn and lean burn engines. However, it is unclear whether the MACT standard for SI-NG-4SRB engines will be the same or nearly the same as the MACT standard for SI-NG-4SLB engines.]

- A lambda of 1.1 corresponds to approximately 2 percent oxygen in the exhaust. An exhaust concentration of 2 percent would not be compatible with the use of NSCR controls as intended for NOx control. In order to use NSCR as intended for NOx control, it would be necessary to adjust the engine to run at 1 percent oxygen or less. However, engines may be able to use other devices to comply with MACT.

- According to some Work Group members, NSCR may not be achievable for all engines in the rich burn subcategory if this definition were adopted. In order to use NSCR as intended for NOx control, it would be necessary to adjust the engine to run at 1 percent oxygen or less. However, for some older models of engines, commercially available air-to-fuel ratio controllers cannot ensure that the engines will operate with exhaust concentrations of 1 percent oxygen or less, at all load conditions, including low-loads. However, engines may be able to use other devices to comply with MACT.

Instances Where the Definition Has Been Used Previously:

- California's Ventura County and Sacramento Air Quality Management Districts, Rules 74.9 and 412, define rich burn engine as follows:

  "A two-stroke or four-stroke spark-ignited engine where the manufacturers original recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio is less than or equal to 1.1.

VI. DEFINE AS ENGINES WITH 4 PERCENT OR LESS EXCESS OXYGEN IN THE EXHAUST

Definition Discussed by the Work Group:

> "Rich burn means a four-stroke, spark-ignited engine where the oxygen content in the exhaust stream before any dilution is 4% or less measured on a dry basis."

Pros:

- Oxygen content of the exhaust is easy to measure on-site and determine whether an engine meets the criteria of 4 percent or less.

- Definition reflects the operating conditions of the engine, not simply the conditions specified by the manufacturer. Therefore, the definition accommodates diverse operating conditions of existing engines that may result in an exhaust gas oxygen content different than that specified by the manufacturer.

- Definition takes into account the possible re-manufacture or re-construction of existing engines, which may result in an exhaust gas oxygen content different than that specified by the manufacturer.

- Definition is used by some engine manufacturers.

- Since the exhaust oxygen limit is set fairly high, it would be difficult for engine owners and operators to adjust the air-to-fuel ratio sufficiently to raise the oxygen level in the exhaust and thereby qualify the engine as a "lean burn engine."

Cons:

- Definition is significantly to the lean side of stoichiometry.

- If the definition relies on exhaust concentration based on the current operating air-to-fuel ratio (not the manufacturer's specifications), owners and operators would have the opportunity to adjust the air-to-fuel ratio to raise the oxygen content and thereby qualify the engine as a “lean burn engine.” The definition does not incorporate sufficient constraints to prohibit engine owners and operators from temporarily adjusting the engine to avoid rich burn regulatory requirements.

[Note: For NOx, regulators were very concerned about this possibility since there were higher NOx emission limitations for lean-burn engines, which relied on different control technologies to reduce NOx. For the RICE MACT standard, similar oxidation control technologies have been identified for both rich burn and lean burn engines. However, it is unclear whether the MACT standard for SI-NG-4SRB engines will be the same or nearly the same as the MACT standard for SI-NG-4SLB engines.]

- An exhaust concentration of 4 percent is not compatible with the use of NSCR as intended for NOx control. In order to use NSCR as intended for NOx control, it would be necessary to adjust the engine to run at 1 percent oxygen or less. However, engines may be able to use other devices to comply with MACT.

- According to some Work Group members, NSCR as intended for NOx control would not be achievable for all engines in the rich burn subcategory if this definition were adopted. In order to use NSCR as intended for NOx control, it would be necessary to adjust the engine to run at 1 percent oxygen or less. However, for some older models of engines, commercially available air-to-fuel ratio controllers cannot ensure that the engines will operate with exhaust concentrations of 1 percent oxygen or less, at all load conditions, including low-loads. However, engines may be able to use other devices to comply with MACT.

Instances Where the Definition Has Been Used Previously:

- EPA AP-42 Emission Factors for Reciprocating Internal Combustion Engines uses this definition.

- Texas environmental regulations, Chapter 106, Exemptions from Permitting, 106.512, defines “rich burn engine” as “a gas-fired spark-ignited engine that is operated with an exhaust oxygen content less than 4.0% by volume.” [Note: The definition in Texas's Chapter 117, Control of Air Pollution from Nitrogen Oxides, defines "rich burn engine" as a spark-ignited, Otto cycle, four-stroke, naturally aspirated or turbocharged engine that is capable of being operated with an exhaust stream oxygen concentration equal to or less than 0.5% by volume, as originally designed by the manufacturer."]

- California’s Bay Area Air Quality Management District Rules and Regulations, BAAWMD Regulation 9-8-205 defines rich burn engine as follows:

  “Any spark or compression ignited internal combustion engine that is designed to be operated with an exhaust stream oxygen concentration of less than 4 percent, by volume. The exhaust gas oxygen content shall be determined from the uncontrolled exhaust stream.”

- California’s South Coast Air Quality Management District Rule 1110.1, includes the following definition:

  “A rich-burn engine is an Otto cycle engine that can be adjusted to run with an exhaust stream oxygen concentration of less than 4 percent by volume.”

- California’s Santa Barbara County APCD Rule 333 defines “rich burn engine” as an engine with 4 percent oxygen in the exhaust, but also limits engines already permitted as “rich burn engines” from changing their designation after the date of rule adoption:

  “Rich-burn engine means a spark-ignited, Otto cycle, or four-stroke naturally aspirated engine that is operated with an exhaust stream oxygen concentration of less than 4 percent by volume. The exhaust gas oxygen content shall be determined from the uncontrolled exhaust stream. Additionally, any engine which is designated as a rich-burn engine on a District Permit on the date of rule adoption shall be a rich-burn engine.”

VII. DEFINE AS ENGINES WITH 1 PERCENT OR LESS EXCESS OXYGEN IN THE EXHAUST

Definition Discussed by the Work Group:

> "Rich burn means a four-stroke, spark-ignited engine where the oxygen content in the exhaust stream before any dilution is 1% or less measured on a dry basis."

Pros:

- Oxygen content of the exhaust is easy to measure on-site and determine whether an engine meets the criteria of 1 percent or less.

- The definition is consistent with the use of NSCR as intended for NOx control, which requires that oxygen be 1 percent or less. With this definition, the use of NSCR as intended for NOx control would be achievable for all rich burn engines.

- Definition reflects the operating conditions of the engine, not simply the conditions specified by the manufacturer. Therefore, the definition accommodates diverse operating conditions of existing engines, which may result in an exhaust gas oxygen content different than that specified by the manufacturer.

- Definition takes into account the possible re-manufacture or re-construction of existing engines, which may result in an exhaust gas oxygen content different than that specified by the manufacturer.

Cons:

- If the definition relies on exhaust oxygen content based on current operating air-to-fuel ratio (not the manufacturer's specifications), engine owners and operators would have the opportunity to adjust the air-to-fuel ratio to raise the oxygen level in the exhaust and thereby qualify the engine as a “lean burn engine.” The definition does not incorporate sufficient constraints to prohibit engine owners and operators from temporarily adjusting the engine to avoid rich burn regulatory requirements.

  [Note: For NOx, regulators were very concerned about this possibility since there were higher NOx emission limitations for lean-burn engines, which relied on different control technologies to reduce NOx. For the RICE MACT standard, similar oxidation control technologies have been identified for both rich burn and lean burn engines. However, it is unclear whether the MACT standard for SI-NG-4SRB engines will be the same or nearly the same as the MACT standard for SI-NG-4SLB engines.]

- While this definition limits rich burn engines to those engines with 1 percent or less exhaust oxygen content, some engine manufacturers use a definition of 4 percent exhaust gas oxygen content.

- The definition limits "rich burn engines" to those engines that may use NSCR as intended for NOx control. However, it is unclear whether this is important for the RICE MACT, because the RICE MACT may permit the use of alternate controls that are consistent with other definitions.

Instances Where the Definition Has Been Used Previously:

- Massachusetts regulations, Title 310, Chapter 7. Air Pollution Control, defines “rich burn engine” as “any stationary reciprocating internal combustion engine that is not a lean burn engine.” “Lean burn engine” is defined as “a stationary reciprocating internal combustion engine in which the amount of O2 in the engine exhaust gases is 1.0% or more.”

- Ohio environmental regulations (OAC 3745-14-01(B)(30), Effective 6/21/94) and Rhode Island (Subsection 27.1.23 of Air Pollution Control Regulation No. 27, Amended 1/16/96) use similar definitions:

- Rich burn engine means an internal combustion engine where the amount of oxygen in the engine exhaust gases is less than one percent, by weight.”

- New York environmental regulations, 6 NYCRR 227-2.2(b)(15), Filed 1/19/94, define “rich burn internal combustion engine” as “any stationary internal combustion engine that is not a lean burn engine as described in paragraph (8) of this subdivision.” Paragraph 8 defines “lean burn internal combustion engine” as “any stationary internal combustion engine that is operated so that the amount of oxygen in the exhaust is 1.0 percent or more, by volume."

- North Carolina environmental regulations, Administrative Code 15A, Chapter 2d, Section 1401(15), Effective 4/1/95, define 1 percent as the break-point for rich burn/lean burn, but limit the definition to engines designed and manufactured for 1 percent exhaust oxygen:

- Rich-burn internal combustion engine means a spark ignition internal combustion engine originally designed and manufactured to operate with an exhaust oxygen concentration less than or equal to one percent."

- New Hampshire environmental regulations (NHAR-Env-A 1211.01(an), Effective 5/20/94) have a similar, but not identical regulation. In this case, "rich burn engine" is defined as "any stationary internal combustion engine that is not a lean burn engine." A "lean burn engine" is defined as "a stationary, internal combustion engine in which the amount of O2 in the engine exhaust gases is 1.0% or more, by weight, unless otherwise specified by the engine manufacturer."

VIII. Conclusions and Recommendations

Engines operating rich of the stoichiometric air-to-fuel ratio are clearly rich burn engines. Technically, when engines operate lean of stoichiometric (stoichiometric correlates to approximately 0.5% oxygen), they are no longer operating in a rich-burn mode. However, according to engine manufacturers, academics, and air regulations developed for NOx control, engines operating slightly lean of stoichiometric are considered "rich burn engines." Air regulatory definitions of "rich burn engines" have included engines operating up to 1 percent oxygen, up to 4 percent oxygen, and up to a lambda of 1.1. In addition, recognizing that engines are adjustable, some regulators have tied the definition of "rich burn engines" to manufacturers' recommended air-to-fuel ratio or exhaust oxygen content to limit the opportunity for source owners and operators to adjust the engine so that it is no longer considered a "rich burn."

From the standpoint of the RICE MACT, it is necessary that the standard be achievable for all engines in each subcategory. For SI-NG-4SRB engines, the RICE Work Group has identified NSCR as the MACT floor. There may be control options for SI-NG-4SRB engines other than NSCR.

Based on the information presented in this paper and the discussions of the RICE Work Group, it is clear that the definition of rich burn engines for the RICE MACT standard is complicated. At this time, the RICE Work Group has not reached consensus on a regulatory definition of “rich burn engine” for the purposes of the MACT standard. The Work Group views at this time may be summarized as follows:

- With regards to the technical characteristics that should be used to define "rich burn engines," some Work Group members believe that exhaust oxygen content should be the basis for the definition of "rich burn engines" because it is easily determined in a precise manner in the field and it provides an indication of the engine's air-to-fuel ratio. Other Work Group members believe that lambda 1.1 should be the basis for the definition of "rich burn engines" because it is independent of fuel, is a technically precise point, and makes compliance determinations definitive.

- With regards to the limits of the definition of "rich burn engines," some Work Group members believe that "rich burn engines" should include only those engines that can use NSCR as a 3-way catalyst for the simultaneous control of NOx, CO, and HC. Other Work Group members believe that "rich burn engines" should include engines beyond those that may use NSCR as a 3-way catalyst, so long as all engines included in the SI-NG-4SRB subcategory could meet the MACT requirements through the use of any device, such as an oxidation catalyst or NSCR used solely for oxidation.

- In order to prevent engine owners/operators from adjusting the operating conditions to avoid rich burn regulatory requirements, some Work Group members believe it is important to link the definition of "rich burn engines" to the manufacturer's specifications for air-to-fuel ratio or exhaust oxygen content or to include other constraints to limit the temporary adjustment of the engine to avoid rich burn regulatory requirements. Other Work Group members believe it is important that the definition of "rich burn engines" not rely solely on the manufacturer's specifications. These Work Group members believe the definition should take into account the possible re-manufacture or re-construction of an existing engine, which may result in engineering and operating characteristics more closely akin to lean burn engines than to rich burn engines. In addition, these Work Group members believe the definition should accommodate diverse operating conditions, which may result in an exhaust gas oxygen content different than that specified by the manufacturer.

The RICE Work Group agrees that the definition for “rich burn engine” should accomplish the following goals:

- The definition should incorporate engines that operate both fuel-rich and slightly lean of stoichiometry.

- The definition should incorporate other engines only where the control needed to meet the MACT regulation is achievable.

- The definition should recognize that existing engines, originally considered “rich-burn,” might have been modified in the field to run at conditions that are significantly lean of stoichiometry.

- The definition should not allow engine owners and operators the opportunity to adjust the engine to lean burn status to avoid rich burn regulatory requirements.

Attachment 14

RICE Work Group Presentation on Emissions Database Assessment

Item for Closure:

Assessment of the EPA ICCR Emissions Database for Reciprocating Internal Combustion Engines (RICE)

presented to:

ICCR Coordinating Committee
Durham, North Carolina

presented by:

Sam Clowney, Tennessee Gas Pipeline
on behalf of the RICE Work Group

September 16, 1998

Summary

- RICE WG has dedicated a significant effort to evaluating the available emissions data for RICE since February 1997
- Assessment of RICE Emissions Database conducted to determine adequacy of emissions data to support the MACT rule development
- Paper documents the work conducted over the past 18 months
- WG recommends that the Coordinating Committee forward this information to EPA

Results of WG Assessment (1)

- Source tests from State and local air regulatory agencies provide “snapshots” of emissions from RICE
  - emissions reported are highly variable -- 6 orders of magnitude for natural gas-fired engines

- While the source tests may have been adequate for compliance purposes, not adequate to:
  - fully evaluate the operating status of the engine when tested
  - draw conclusions about the effects of operating conditions on HAPs

Results of WG Assessment (2)

- Database does not contain data to evaluate the effectiveness of catalytic controls, such as non-selective catalytic reduction (NSCR) or oxidation catalysts, throughout the full range of engine operating conditions
  - 8 emissions tests for NSCR
  - 6 emissions tests for oxidation catalysts
- Data for NSCR include a limited number of pollutants and high detection limits (FTIR with a 0.5 ppm detection limit)
- Data for oxidation catalysts lack sufficient emissions data before and after to estimate representative control efficiency

Results of WG Assessment (3)

- Additional emissions data would better support the regulatory development of the RICE MACT standard
  - Key data gaps:
    - » effectiveness of after-treatment control on HAP reductions
    - » effectiveness of combustion modifications on HAP reductions
    - » typical emissions for engines throughout the operating range
- Test Plan designed to address effectiveness of after-treatment control on HAP emissions from RICE
  - data gaps in existing RICE Emissions Database
  - limited understanding of effects of combustion modification on HAP emissions from RICE -- research ongoing

Results of WG Assessment (4)

- Emissions based solely on non-detects should not be used for regulatory purposes
  - Process recommended by T&M Protocol WG should be used to evaluate non-detect data
  - Reported non-detects should be carefully documented to ensure MACT decisions not based on non-detect values
- RICE WG concurs with T&M guidance on non-detects
- RICE WG recommends that this guidance be used to evaluate any non-detects reported as a part of the RICE Test Plan

Results of WG Assessment (5)

- For aldehyde emissions, questions remain about CARB 430 data for lean -burn natural gas-fired engines:
  - CARB 430 data from 3 emissions tests for natural gas-fired lean burn engines have evidence of interference (data flagged)
  - Other emissions tests with CARB 430 data had insufficient information for the WG to conclusively determine whether interference had occurred

- Most of WG disagreed with EPA conclusion that available data from CARB 430 and FTIR are "equivalent"
- These WG members believe that further analysis of the data is warranted

Conclusions (1)

WG agrees that additional emissions data would better support the ICCR rule development, since:

- Variability of the emissions data in the RICE Emissions Database cannot be explained with available information.
- Information about the engine process during emissions testing from state and local agencies is insufficient to understand how emissions vary over full operating range.
- Emissions data before and after catalytic control devices that may reduce HAP emissions, including NSCR and oxidation catalysts, is inadequate to evaluate the effectiveness of those devices in reducing HAP emissions throughout the full operating range.
- For aldehyde emissions, there are questions remaining about existing data for natural gas-fired lean-burn engines from tests using CARB 430 and other DNPH-based methods. The WG has recommended FTIR for future EPA testing of natural gas lean burn engines.

Conclusions (2)

- RICE WG urges EPA to conduct RICE Test Plan
- WG recommends that EPA rely on data from the RICE Test Plan and similar data of that caliber to assess the efficiency of HAP emissions control technology, such as NSCR and oxidation catalysts, throughout the full operating range
- HAP emissions data in the database does provide “snapshot” emissions data for a variety of RICE -- this data is relevant to EPA’s analysis of the achievability of any emission limitations under consideration for the RICE MACT
- WG underscores need to implement the T&M Protocol WG guidance on non-detects for all emissions data that may be used to support the MACT rule development

Recommendation to CC

- RICE WG recommends that the CC forward the materials developed by the WG to EPA as a recommendation:
  - Paper documents WG consensus views on the available emissions data in the ICCR Database
  - Paper further documents that additional emissions data would better support the RICE MACT standard -- need to conduct RICE Test Plan
  - Paper underscores need to implement T&M Protocol WG guidance on the use of non-detects

Attachment 15

Paper on Assessment of RICE Emissions Database
(Closure Item)

Assessment of the EPA ICCR Emissions Database for Reciprocating Internal Combustion Engines

Prepared for:
Coordinating Committee of the
Industrial Combustion Coordinated Rulemaking (ICCR)

Prepared by:
Reciprocating Internal Combustion Engine work group
Of the Industrial Combustion Coordinated Rulemaking

September 4, 1998

TABLE OF CONTENTS

I. INTRODUCTION

This paper presents the results of the Reciprocating Internal Combustion Engine (RICE) Work Group's assessment of the ICCR Emissions Database for RICE (RICE Emissions Database). The RICE Work Group has dedicated a significant effort to evaluating the available emissions data for RICE since February 1997. The assessment of the RICE Emissions Database was conducted in the context of determining the adequacy of the emissions data in the database to support the MACT rule development for stationary RICE. The Work Group developed this paper to document the work conducted over the past 18 months. The Work Group recommends that EPA consider this information in developing the MACT standard for stationary RICE.

The Emissions Database includes the available emissions data identified to date by EPA and the RICE Work Group to support the ICCR rule development for engines. The RICE Work Group and the ICCR Coordinating Committee have recommended to EPA that additional emissions data would better support the ICCR rule development. EPA has agreed to conduct the RICE Test Plan at the Colorado State University (CSU) Engines and Energy Conversion Laboratory. Members of the Work Group continue to support the RICE Test Plan by sharing the data collection and analysis burden. The recommendation for additional testing was based largely on the results of the Work Group’s review of emissions data included in the ICCR Emissions Database for RICE.

Section II of this paper provides a description of the characteristics of the emissions data currently included in the ICCR Emissions Database for RICE, including a breakdown of the data by subcategory and a summary of the available emissions data for control devices. Section III provides a summary of the results of the Work Group's review of the emissions data in the database. The final section of this paper presents the Work Group's conclusions and recommendations regarding the emissions data included in the database.

II. CHARACTERISTICS OF THE HAPS EMISSIONS DATA INCLUDED IN THE RICE EMISSIONS DATABASE

The RICE Emissions Database (version 2.0) includes 92 test reports, with over 448 emissions tests for stationary RICE -- 171 emissions tests include HAP emissions data, 344 emissions tests include criteria pollutant data, and 67 tests include both HAP and criteria pollutant data. The tests incorporate the measurement of 45 HAPs. For each test report, EPA has calculated emission factors for HAPs in a consistent manner based on the emission concentration reported. When a single test included more than one run, the concentrations reported in each run are averaged. When a test includes HAPs that were not detected at levels above the method's detection limit (non-detects), EPA has calculated emission factors based on a percentage of the method's detection limit. EPA has flagged those values calculated based on a percentage of the detection limit with a less-than sign (<). If all runs conducted for an emissions test resulted in non-detects, EPA has flagged the data with a double less-than sign (<<). If concentrations were measured in at least one run, and other runs included non-detects, EPA has flagged the data with a single less-than sign (<). EPA included these data flags to identify those emission factors based on non-detects and to facilitate review of these data in the future. A description of the development of the emissions database, including assumptions used in the calculations is provided as **Appendix A**. EPA and the RICE Work Group have performed quality assurance reviews of a representative number of the emissions test reports and determined which reports should be considered adequate for general assessment of HAP emissions from stationary RICE. This review is discussed in **Section III** of this paper.

A summary of the sources of the emissions data in the ICCR Emissions Database is provided below. In addition, a summary of the emissions data included in the database for the RICE subcategories is presented, along with a summary of the emissions data for control devices.

A. Sources of Emissions Data

The RICE Emissions Database was compiled by EPA principally from the following sources:

- Source test reports (compliance tests) identified in EPA's Source Test Information Retrieval System (STIRS),
- Source test reports (compliance tests) submitted by Work Group members, and
- Emissions tests conducted by the Gas Research Institute (GRI).

No standard protocol was used to conduct the emissions tests included in the RICE Emissions Database. The HAPs reported, test methods used, detection limits, operating conditions tested, and reasons why testing was performed vary significantly from test to test. Most of the STIRS test reports with HAP emissions data come from California air pollution control districts and were conducted by source owners and operators to comply with California's AB2588 air toxic regulation. In those cases, test methods developed and approved by the California Air Resources Board (CARB) are generally used to quantify emissions. The target HAPs for the California tests vary since the target HAPs were negotiated with the local air pollution control district.

The database also includes source test reports collected by Work Group members. EPA and Mr. Don Price of the Ventura County Air Pollution Control District have requested copies of additional emissions test reports for stationary RICE from various districts in California. Although the Work Group has not reviewed the additional test reports, the Work Group agreed that the data from these test reports should be included in the RICE Emissions Database. Based on available information, it is anticipated that these test reports will be similar in quality to those compiled by EPA from the California districts.

The database also includes 112 emissions tests conducted by the Gas Research Institute (GRI) for natural gas-fired engines. These emissions tests were conducted by GRI in cooperation with GRI member companies.

B. Emissions Data by Subcategory

The RICE Work Group has identified the following subcategories for existing RICE:

- Spark-Ignition, Natural Gas 4-Stroke Rich Burn Engines

- Spark-Ignition, Natural Gas 4-Stroke Lean Burn Engines
- Spark-Ignition, Natural Gas 2-Stroke Lean Burn Engines
- Spark-Ignition, Digester Gas and Landfill Gas Engines
- Spark-Ignition, Propane, Liquid Petroleum Gas (LPG), and Process Gas Engines
- Spark-Ignition, Gasoline Engines
- Compression-Ignition, Liquid Fuel Engines (diesel, residual/crude oil, kerosene/naphtha)
- Compression-Ignition, Dual Fuel Engines
- Emergency Power Units
- Small Engines (200 brake horsepower or less)

The RICE Emissions Database includes emissions data for all the subcategories identified by the RICE Work Group, except for Spark-Ignition, Gasoline Engines and Compression-Ignition, Dual Fuel Engines. Engines tested range in size from 54 horsepower (hp) to 5,500 hp. A summary of the number of emissions tests included in the database, by subcategory, is presented in **Table 1**. Most of the emissions data are for natural gas-fired engines and diesel engines, which, according to the ICCR Population Database, represent over 95 percent of stationary RICE.

For the fuels other than natural gas and diesel, there are a limited number of HAP emissions tests included in the RICE Emissions Database. For the Spark-Ignition, Digester Gas and Landfill Gas subcategory, 14 emissions tests are included in the database for digester gas, and one emissions test is included in the database for landfill gas. For the Spark-Ignition, Propane, LPG, and Process Gas subcategory, 1 HAP emissions test is included in the database for propane (on a small engine) and no HAP emissions tests are included for process gas or LPG. For Compression-Ignition, Liquid-Fuel Engines, all emissions tests included in the RICE Emissions Database are for diesel fuel, and no emissions tests are included for kerosene/naphtha, or heavier fuels, such as residual/crude oil. For the Emergency Power Units subcategory, three emissions tests indicate the engines are generators, but there is insufficient information to determine if they are for emergency use. Two of these tests indicate that multiple engines were included in the tests (common stack) and therefore, it is unclear which engine(s) are represented by the emissions test data.

Table 1. HAP Emissions Tests for Each RICE Subcategory

RICE Subcategory	Emissions Tests
Spark-Ignition, Natural Gas 4-Stroke Rich Burn Engines[1]	22
Spark-Ignition, Natural Gas 4-Stroke Lean Burn Engines[1]	32
Spark-Ignition, Natural Gas 2-Stroke Lean Burn Engines[1]	56
Spark-Ignition, Digester Gas and Landfill Gas Engines	15
Spark-Ignition, Propane, LPG, and Process Gas Engines[2]	0
Spark-Ignition, Gasoline Engines	0
Compression-Ignition, Liquid-Fuel Engines (diesel, residual/crude oil, kerosene/naphtha)	26
Compression-Ignition, Dual Fuel Engines	0
Emergency Power Units	Unknown[3]
Small Engines (200 brake horsepower or less)	19

[1] One emissions test for a natural gas-fired engine could not be subcategorized.

[2] One emissions test report, with seven emissions tests, was included in the Database for an engine firing propane. Since the engine is rated at 39 hp, these tests are included in the small engine subcategory.

[3] Three emissions tests were conducted on generators, but the emissions tests do not indicate whether the engines are used for emergency power.

C. HAP Emissions Data for Engines with Criteria Pollutant Control Devices

Most HAP emissions tests included in the RICE Emissions Database were conducted on RICE without emissions controls. In some cases engines with NOx controls, including pre-combustion chambers (PCC), low emissions combustion (LEC), selective catalytic reduction (SCR), and non-selective catalytic reduction (NSCR), were tested. Also, 6 tests were conducted on engines using oxidation catalysts for carbon monoxide (CO) control. **Table 2** includes a summary of the emissions tests for criteria pollutant control devices, by subcategory.

Table 2. HAP Emissions Tests for Criteria Pollutant Control Devices

RICE Subcategory	Criteria Pollutant Control Devices Tested	
Spark-Ignition, Natural Gas 4-Stroke Rich Burn Engines	Non-Selective Catalytic Reduction	8
	Pre-Combustion Chamber	1
	Pre-Stratified Charge	1
Spark-Ignition, Natural Gas 4-Stroke Lean Burn Engines	Pre-Combustion Chamber	13
	Pre-Stratified Charge	2
	Selective Catalytic Reduction	5
Spark-Ignition, Natural Gas 2-Stroke Lean Burn Engines	Pre-Combustion Chamber	3
	Oxidation Catalyst for CO Reduction	6
Spark-Ignition, Digester Gas and Landfill Gas Engines	None	
Spark-Ignition, Propane, LPG, and Process Gas Engines	None	
Spark-Ignition, Gasoline Engines	None	
Compression-Ignition, Liquid-Fuel Engines (diesel, residual/crude oil, kerosene/naphtha)	Selective Catalytic Reduction	1
Compression-Ignition, Dual Fuel Engines	None	
Emergency Power Units	None	
Small Engines (200 brake horsepower or less)	None	

III. RESULTS OF WORK GROUP ASSESSMENT OF THE EMISSIONS DATABASE

In February 1997, the ICCR Coordinating Committee requested that Work Groups review available emissions to determine whether there was sufficient data available to support the ICCR rulemaking and to identify emissions data gaps that would need to be addressed to support the rulemaking. The RICE Work Group established the Emissions Subgroup to review the emissions data in the EPA ICCR Emissions Database for RICE. Members of the Subgroup reviewed the emissions test reports that were the source of the ICCR emissions data for RICE.

As a part of this review, the RICE Work Group conducted a detailed QA\QC review of the emissions test reports included in the database, largely emissions tests submitted by source owners and operators in California to respond to requirements from State or local air regulatory agencies. The Work Group used the information collection request (ICR) designed by the Work Group for RICE as the format for the QA\QC review. A copy of the data form used by the Work Group to conduct the QA\QC review is provided in **Appendix B.**

The results of the Work Group's review of the emissions database may be summarized as follows:

1. Source tests from State and local air regulatory agencies provide "snapshots" of emissions from RICE in real-world applications. The source tests include insufficient information to fully evaluate the operating status of the engine when tested or to draw conclusions about the effects of operating conditions on HAPs. Where possible, EPA contacted the facilities and added information about the engineering parameters of the engines tested. In addition, the information about the engine family was added based on the engine manufacturer and model.

2. The RICE Emissions Database does not contain data to evaluate the effectiveness of catalytic controls, such as non-selective catalytic reduction (NSCR) or oxidation catalysts, throughout the full range of engine operating conditions.

3. Additional emissions data would better support the regulatory development of the RICE MACT standard.

4. Emissions estimates based solely on non-detects should not be used for regulatory purposes. [As noted above, EPA has flagged the emission factors in the ICCR Emissions Database that are based on non-detects.]

5. CARB 430 data from 3 emissions tests for natural gas-fired lean burn engines has evidence of interference. Other emissions tests with CARB 430 data had insufficient information for the Work Group to conclusively determine whether interference had occurred.

Additional discussion of the reviews conducted by the Work Group to draw these conclusions is provided below.

A. Emissions Data in Source Tests from State and Local Agencies

In March 1997, the Emissions Subgroup of the RICE Work Group reported on the results of the assessment of emissions data in source tests from state and local agencies. The Subgroup noted that the emission levels reported in the source tests were highly variable. For example, emissions of formaldehyde reported in the database for natural gas-fired engines cover six orders of magnitude, from 4.43E-07 pounds per million British Thermal Unit (lb/MMBTU) to 7.23E-01 lb/MMBTU. [The data for lean burn natural gas-fired engines are presented in **Figures 1** and **2**.] The Subgroup suggested that the variability could be attributed to two possible causes: 1) reported formaldehyde levels in some cases may be artificially low due to interference with DNPH-based test methods, and 2) emissions may be affected by the operating condition of the engine when tested.

When the Subgroup reviewed the test reports, the Subgroup noted that although the source tests were generally complete as it relates to documentation of the stack testing procedures and QA\QC for the test methods, the tests lacked information about the engine process. The RICE Work Group agreed that the HAP emissions tests obtained from state and local air regulatory agencies were conducted by source owners and operators in response to air regulatory requirements. Therefore, the goals for the testing were limited to the air regulatory requirements, rather than the goal of documenting emissions throughout the operating range or determining the effects of engine operating conditions on HAP emissions. Tests that provide detailed information about engine emissions throughout the full range of engine operating conditions are not required in the regulatory context, and therefore, tests with that level of detail are not available from state and local air regulatory agencies.

The test reports lacked key information about engineering and operating parameters that could affect HAP emissions. For example, the manufacturer and model of the engine were often lacking in test reports. Information about whether the engine was a 2-stroke or 4-stroke cycle was absent. The air-to-fuel ratio was often lacking, as was the horsepower and speed (rated and as tested). In addition, the engines apparently were tested in an "as-found" condition without full consideration of the reciprocating internal combustion process.
The Subgroup concluded that there was insufficient information in the test reports to account for the unexplained variability in the emissions data included in the ICCR Emissions Database for RICE. The Subgroup also concluded that, apparently, there are no existing data for testing a single engine over the entire envelope of operating conditions.

Based on the RICE Work Group's review, several key parameters were identified that would be necessary to fully evaluate the emissions data included in the RICE Emissions Database, including the following:

- Fuel used during emissions testing
- Engine manufacturer and model
- Engine subcategory
- Horsepower and speed (rated and as-tested)

Where possible, EPA contacted the tested facilities and obtained missing information. In general, the additional information obtained from the facilities included engine manufacturer and model and rated horsepower and speed. Information about the operating conditions of the engine during the emissions tests generally were not available. Information about engine subcategory was added to the database by using the engine manufacturer and model and information available from the engine manufacturers to determine which subcategory the engine should be placed in.

It is the conclusion of the RICE Work Group that, for those tests that met QA\QC review, the emissions data in source tests from state and local agencies only provided "snapshots" of the HAP emissions from the engines at the time of testing. The emissions tests evidently were not conducted over multiple operating conditions that might be seen by the engine in its application. Also, key information about the engine status was missing from the test reports, and could not be added. While this may have been sufficient for compliance purposes, it is not sufficient for determining HAP emissions throughout the operating range or for determining the effect of engine operating conditions on HAP emissions. Therefore, the RICE Work Group concluded that the data was inadequate to fully evaluate the range of emissions that would be anticipated from the unit throughout its operating range. In addition, the Work Group concluded that data included in the Emissions Database (version 2.0) should not be used to evaluate the effects of operating conditions on HAP emissions.

Emissions data throughout the operating range are necessary to fully evaluate HAP emissions from stationary RICE because engine operating parameters affect the physical and chemical mechanisms that result in the production of formaldehyde and other similar HAPs in ways that are indirect, complicated and often interrelated. For example, for large-bore natural gas-fired engines, increasing load typically increases the captured fuel air ratio, average cylinder temperature and exhaust temperatures, and peak pressure. It also affects mixing, level of turbulence, and flame propagation in unknown ways. This makes any evaluation of the effects of engine operation on formaldehyde both difficult and speculative given the present state of understanding.[10]

B. Emissions Data to Determine Efficiencies of Catalytic Controls

The RICE Work Group reviewed the emissions tests reports to determine if there was sufficient information to determine the effectiveness of controls that may reduce HAPs. Based on the Work Group's review of existing control devices, the group determined that existing catalytic controls for carbon monoxide (CO) reduction may also oxidize certain HAPs, such as formaldehyde. The Work Group identified non-selective catalytic reduction (NSCR) as a possible MACT control for natural gas-fired 4-stroke rich burn engines. Oxidation catalysts were identified as a possible MACT control for natural gas-fired lean-burn engines and for diesel engines. Catalytic controls were not identified for the Digester Gas/Landfill Gas subcategory because these fuels commonly contain siloxanes and other trace components, which foul catalysts.

The RICE Emissions Database includes eight emissions test for non-selective catalytic reduction (NSCR) on natural gas-fired 4-stroke rich burn engines. There are six emissions tests for oxidation catalysts for lean-burn engines.

[10] Factors Affecting the Measurement of CH_2O in Large-Bore Natural Gas Engines, C.E. Mitchell and D.B. Olsen, February 1998, ASME Paper 98-ICE-81, ICE-Vole. 30-1, 1998 Spring ASME-ICE Division Engine Technology Conference.

The RICE Work Group concluded that there was insufficient data to evaluate the effectiveness of NSCR and oxidation catalysts over the full operating range. The data in the Emissions Database for NSCR include a limited number of pollutants and high detection limits (FTIR with a 0.5 ppm detection limit), so that non-detects were frequently reported. The data in the Emissions Database for oxidation catalysts lack sufficient emissions data before and after the control device to estimate representative control efficiency, and only a small portion of the pollutants were measured before and after controls.

C. Additional Emissions Data Would Better Support the RICE MACT

The RICE Work Group has concluded that additional emissions data would better support the ICCR rule development. This conclusion was reached as a result of the Work Group's review of emissions data available to the ICCR process in the EPA ICCR Emissions Database for RICE. The Work Group identified the following key emissions data gaps:

1. data to determine the effectiveness of after-treatment control devices to reduce formaldehyde and other HAPs;

2. data to evaluate the effectiveness of combustion modifications to reduce formaldehyde and other HAPs;

3. data to determine typical emissions for engines throughout the operating range.

The Work Group designed the RICE Test Plan (forwarded to EPA by the Coordinating Committee) to provide data to assess the effectiveness of after-treatment control devices to reduce formaldehyde and other HAPs. The Work Group designed the test plan to address this data gap for the following reasons:

- Emissions data to demonstrate the effectiveness of possible MACT control devices for existing RICE is a data gap in the ICCR Emissions Database for RICE.

- Understanding of the effects of combustion modifications on HAPs is in its infancy, and would require a very extensive research program to identify potential control techniques, along with confirming testing.

- EPA has endorsed the use of ICCR emissions testing dollars to achieve this goal.

The RICE Test Plan also will provide data to partially fill the data gap on baseline emissions from engines, since pre-controlled emissions throughout a 16-point test matrix of operating conditions will be recorded during the testing program.

D. Non-Detect Values

In accordance with the guidance provided by the Testing and Monitoring Work Group (TMDETECT.pdf), the RICE Work Group reviewed non-detect values at the Work Group meeting on November 20, 1997. As a result of the meeting, the Work Group resolved to accept the ICCR Testing and Monitoring Work Group's recommendations, including the following:

- No decisions leading to requirements for control devices or emissions limits on combustion processes should be made that are based on emission levels derived from default HAP concentrations calculated from method detection levels.

- The process recommended by the ICCR Testing and Monitoring Work Group should be used to evaluate non-detect data, including use of 1/2 of detection limits for existing data.

- Where non-detects are present, they should be carefully documented to ensure that MACT decisions are not made based on non-detect values.

As indicated above, EPA has flagged emission factors in the ICCR Emissions Database that were calculated based on non-detects. **Table 3** presents the pollutants, by subcategory, for which all emission estimates in the database are based on non-detects only. **Table 4** presents those pollutants, by subcategory, for which some emission estimates are based on non-detects and some emission estimates are based on measured concentrations.

The RICE Work Group concurs with the Testing and Monitoring Work Group's recommendations regarding non-detects. The Work Group recommends that this guidance be used by EPA in evaluating emissions data in the RICE Emissions Database that includes non-detect values. Also, the Work Group recommends that this guidance be used to evaluate any non-detects that are reported as a part of the emissions testing under the RICE Test Plan.

Table 3. Pollutants, by Subcategory, for Which All Emissions Estimates in the Database are Based on Non-Detects Only

RICE Subcategory	Pollutant	Number of Emission Estimates Based on Non-Detects Only
Spark-Ignition, Natural Gas 4-Stroke Rich Burn Engines	1,1,2-Tetrachloroethane	6
	1,1-Dichloroethane	6
	1,2-Dichloroethane	6
	1,2-Dichloropropane	6
	1,3-Dichloropropene	6
	Carbon Tetrachloride	6
	Chlorobenzene	6
	Chloroform	6
	Ethylene Dibromide	6
	Styrene	6
	Vinyl Chloride	6
Spark-Ignition, Natural Gas 4-Stroke Lean Burn Engines	1,1,2,2-Tetrachloroethylene	9
	1,1,2-Tetrachloroethane	9
	1,1-Dichloroethane	9
	1,2-Dichloroethane	9
	1,2-Dichloropropane	9
	1,3-Dichloropropene	9
	Carbon Tetrachloride	9
	Chlorobenzene	9
	Chloroform	9
	Ethylene Dibromide	9
	Vinyl Chloride	9

Table 3. Pollutants, by Subcategory, for Which All Emissions Estimates in the Database are Based on Non-Detects Only (Continued)

RICE Subcategory	Pollutant	Number of Emission Estimates Based on Non-Detects Only
Spark-Ignition, Natural Gas 2-Stroke Lean Burn Engines	1,1,2,2-Tetrachloroethylene	6
	1,1,2-Tetrachloroethane	6
	1,1-Dichloroethane	6
	1,2-Dichloroethane	6
	1,2-Dichloropropane	6
	1,3-Dichloropropene	6
	Carbon Tetrachloride	6
	Chlorobenzene	6
	Chloroform	6
	Ethylene Dibromide	6
	Vinyl Chloride	6
Spark-Ignition, Digester Gas and Landfill Gas Engines (all non-detects are for Digester Gas only)	1,1,1-Trichloroethane	14
	1,3-Butadiene	14
	1,4-Dioxane	14
	Carbon Tetrachloride	8
	Chloroform	14
	Ethylene Dibromide	11
	Ethylene Dichloride	14
	Tetrachloroethylene	14
	Trichloroethylene	14
	Vinyl Chloride	14
	Vinylidene Chloride	14
Spark-Ignition, Propane, LPG, and Process Gas Engines	None	
Spark-Ignition, Gasoline Engines	None	
Compression-Ignition, Liquid-Fuel Engines (diesel, residual/crude oil, kerosene/naphtha)	Beryllium	3
	Selenium	3
Compression-Ignition, Dual Fuel Engines	None	
Emergency Power Units	Unknown	

Table 3. Pollutants, by Subcategory, for Which All Emissions Estimates in the Database are Based on Non-Detects Only (Continued)

Small Engines (200 brake horsepower or less)	1,1,1-Trichloroethane (Digester Gas)	3
	1,3-Butadiene (Digester Gas)	3
	1,4-Dioxane (Digester Gas)	3
	Carbon Tetrachloride (Digester Gas)	3
	Chloroform (Digester Gas)	3
	Ethylene Dibromide (Digester Gas)	3
	Ethylene Dichloride (Digester Gas)	3
	Naphthalene (Propane & Natural Gas)	9
	Tetrachloroethylene (Digester Gas)	3
	Trichloroethylene (Digester Gas)	3
	Vinylidene Chloride (Digester Gas)	3

Source: ICCR Emissions Database Version 2.0, LB/MMBtu Report

Table 4. Pollutants, by Subcategory, for Which Some Non-Detects and Some Measured Concentrations Were Reported

RICE Subcategory	Pollutant	Number of Emission Estimates Based on Non-Detects Only	Number of Emission Estimates Based on Measured Concentrations
Spark-Ignition, Natural Gas 4-Stroke Rich Burn Engines	1,1,2,2-Tetrachloroethylene	5	1
	Acrolein	6	7
	Acetaldehyde	6	7
	Ethylbenzene	6	5
	Formaldehyde	3	15
	Methylene Chloride	2	4
	Naphthalene	5	3
	Toluene	3	13
	Xylene(s)	6	10
Spark-Ignition, Natural Gas 4-Stroke Lean Burn Engines	Acrolein	11	8
	Acetaldehyde	13	3
	Ethylbenzene	4	10
	Formaldehyde	1	22
	Methylene Chloride	4	5
	Styrene	9	1
	Xylene(s)	1	13
Spark-Ignition, Natural Gas 2-Stroke Lean Burn Engines	Acrolein	31	8
	Acetaldehyde	33	16
	Ethylbenzene	7	9
	Methanol	9	33
	Naphthalene	1	1
	Styrene	6	3
	Xylene(s)	7	11

Table 4. Pollutants, by Subcategory, for Which Some Non-Detects and Some Measured Concentrations Were Reported (Continued)

RICE Subcategory	Pollutant	Number of Emission Estimates Based on Non-Detects Only	Number of Emission Estimates Based on Measured Concentrations
Spark-Ignition, Digester Gas and Landfill Gas Engines	Acrolein	1	13
	Benzene	1	13
	Dichlorobenzene	8	6
	Methylene Chloride	2	12
	Styrene	7	7
	Xylene	1	13
Spark-Ignition, Propane, LPG, and Process Gas Engines	None		
Spark-Ignition, Gasoline Engines	None		
Compression-Ignition, Liquid-Fuel Engines (diesel, residual/crude oil, kerosene/naphtha)	1-3, Butadiene	1	1
	Formaldehyde	8	17
	n-Hexane	1	1
Compression-Ignition, Dual Fuel Engines	None		
Emergency Power Units	Unknown		
Small Engines (200 brake horsepower or less)	Acrolein (Digester Gas)	1	5
	Vinyl Chloride (Digester Gas)	2	1

Source: ICCR Emissions Database Version 2.0, LB/MMBtu Report

E. CARB 430 Data for Natural Gas-Fired Lean Burn Engines

In accordance with the guidance provided by the Testing and Monitoring Work Group (FORMALD1.WP6), the RICE Work Group reviewed the issue of formaldehyde data for natural gas-fired lean-burn engines collected using methods, such as CARB 430, that rely on a DNPH solution to quantify formaldehyde concentrations. The Gas Research Institute (GRI) first advised EPA that there could be NO2 depletion of the DNPH solution when DNPH-based methods are used on natural gas-fired lean-burn engines. In the case of high NO2 levels, the DNPH may be depleted so that formaldehyde levels for lean-burn engines are underreported. GRI had noted the problem when conducting side-by-side testing with its EPA-approved method, using FTIR, and the CARB 430 method, using a DNPH solution. CARB 430 data is included in the RICE Emissions Database for both 4-stroke lean burn and 2-stroke lean burn natural gas-fired engines.

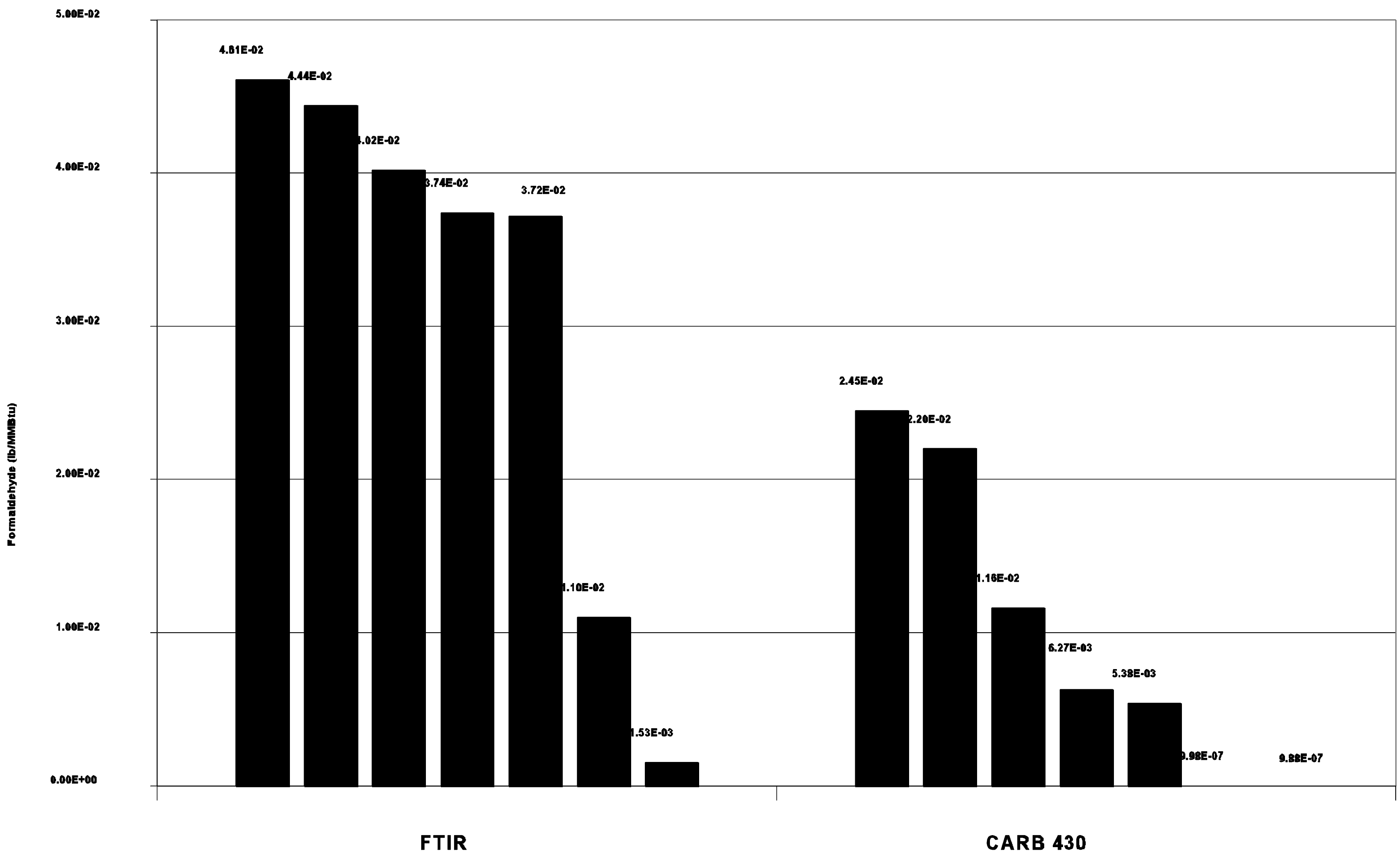
The Work Group initiated the review of CARB 430 data in the Work Group meeting on November 20, 1997. As a result of the meeting, the Work Group requested that EPA compare the CARB 430 data for natural gas-fired lean burn engines to data collected for lean burn engines using FTIR. The criteria for review were based on the recommendations of the Testing and Monitoring Work Group and recommendations from Mr. Jim McCarthy of the Gas Research Institute (GRI).

The results of EPA's review were reported to the Work Group in a memorandum of March 5, 1998. Based on EPA's review, a total of 3 emissions tests, of 16 tests reviewed, included adequate information to determine that there was a problem with the CARB 430 data. These emissions tests have been tagged with an "x" in the database (for pollutants measured with CARB 430) to indicate that the emissions tests do not include acceptable HAP emissions data for those pollutants measured with CARB 430.

EPA reported that the 13 other emissions tests conducted with CARB 430 did not contain sufficient information to determine definitively that there was interference with the method. EPA also conducted a preliminary statistical analysis of the CARB 430 data. Based on that preliminary analysis, EPA concluded in the March 5 memorandum that the remaining data from CARB 430 and FTIR for 4-stroke lean burn and 2-stroke lean burn engines are equivalent. Most of the RICE Work Group members did not concur with EPA's conclusion that the data are equivalent. These Work Group members believe that questions remain about the CARB 430 data for natural gas-fired lean burn engines and that further analysis of the data is warranted.

The formaldehyde emissions data included in the RICE Emissions Database for natural gas-fired 4-stroke lean burn engines is presented in **Figure 1**. The formaldehyde emissions data included in the database for natural gas-fired 2-stroke lean burn engines is presented in **Figure 2**.

Figure 1. Formaldehyde Values for Natural Gas-Fired 4-Stroke Lean Burn Engines



(data presented are from independent testing, not simultaneous testing)

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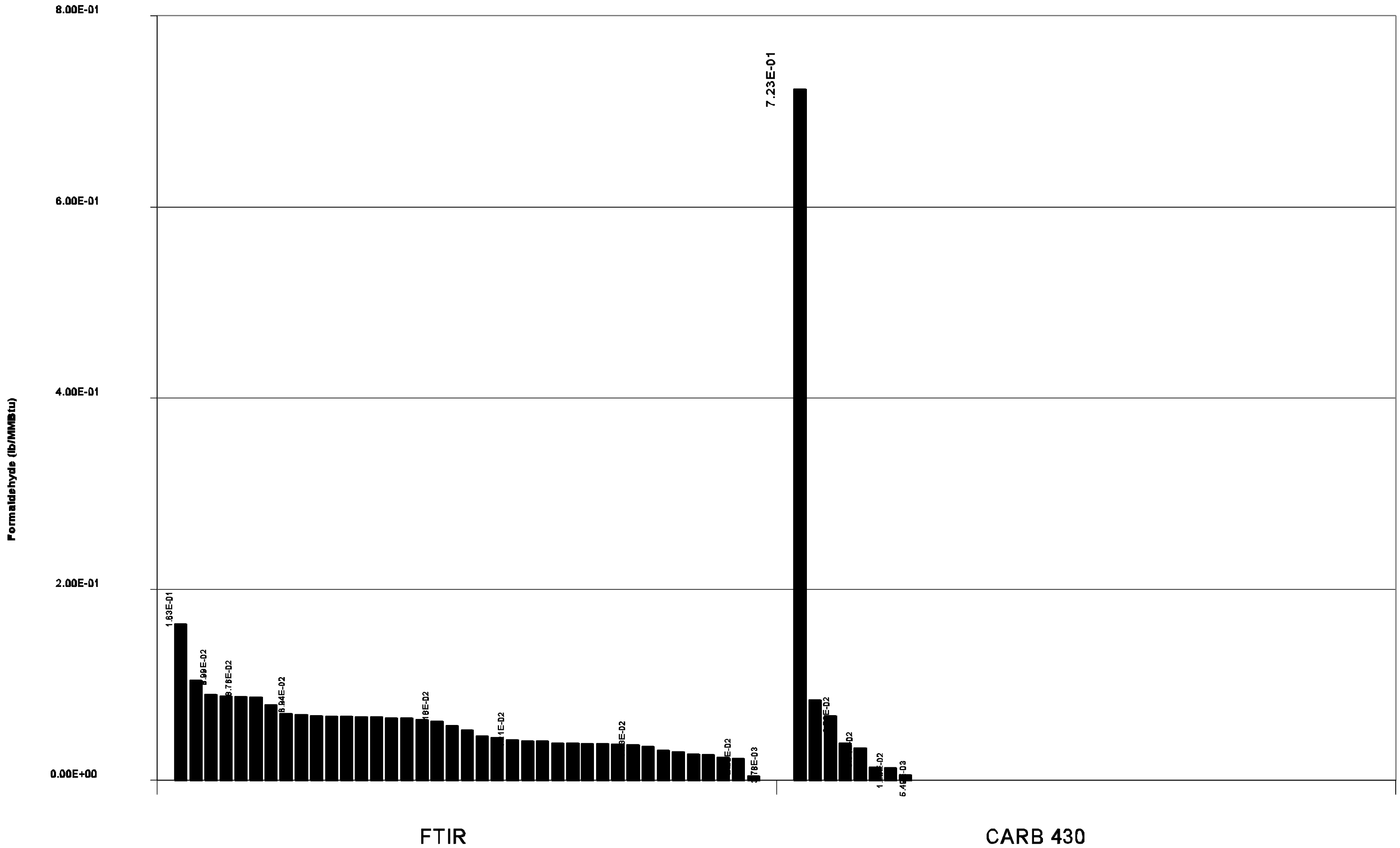
Figure 2. Formaldehyde Data for Natural Gas-fired 2-Stroke Lean Burn Engines



(data presented are from independent testing, not simultaneous testing)

kam\N:\TTN\SEPCC\FLDR\CC16SE8C.WPD

IV. CONCLUSIONS AND RECOMMENDATIONS

RICE Work Group concludes that additional emissions data would better support the ICCR rule development for the following reasons:

- Variability of the emissions data in the RICE Emissions Database cannot be explained with available information.

- Information about the engine process during emissions testing from state and local agencies is insufficient to understand how emissions vary over full operating range.

- Emissions data before and after catalytic control devices that may reduce HAP emissions, including NSCR and oxidation catalysts, is inadequate to evaluate the effectiveness of those devices on reducing HAP emissions throughout the full operating range.

- There are questions remaining about existing emissions data for natural gas-fired lean-burn engines from tests using CARB 430 and other DNPH-based methods (where NO2 may have depleted the DNPH solution). The RICE Work Group has recommended that FTIR be used to measure formaldehyde emissions in future EPA emissions testing for natural gas lean burn engines.

The RICE Work Group urges EPA to conduct the RICE Test Plan at Colorado State University (CSU) to address these data issues. In addition, the Work Group recommends that EPA rely on data from the RICE Test Plan and similar data of that caliber to assess the efficiency of HAP emissions control technology, such as NSCR and oxidation catalysts, throughout the full operating range. Although the RICE Emissions Database does not adequately address the issues listed above, there still may be appropriate uses for the data as a part of the regulatory development for RICE. The data does provide "snapshot" emissions data for a variety of stationary RICE. This data is relevant to EPA's analysis of the achievability of any emission limitations under consideration for the RICE MACT.

Finally, the RICE Work Group underscores the need to implement the Testing and Monitoring Work Group guidance on non-detects for all emissions data that may be used to support the MACT rule development.

APPENDIX A

HAP Emission Data Calculations for RICE Emissions Database

EPA developed a Microsoft Access database for HAP emissions data for reciprocating internal combustion engines. The RICE Emissions Database includes the measured emissions concentrations and all other parameters necessary to calculate emission rates and factors. The database also includes physical and operational parameters which may affect HAP emissions. A total of 1386 records from 30 test reports are included in the database. Each record contains information from up to three test runs for an identified HAP.

Unreported emissions are presented as "NR." Unreported emissions are the result of missing parameters such as pollutant concentration, fuel type, engine type and size, stack exhaust flowrate, or fuel consumption levels. Typically, each test consisted of three test runs. For the tests where at least one run (but not all runs) revealed an undetected concentration, a "<" sign precedes the calculated emission rates and factors. In cases where the pollutant was not detected in all test runs, the emission concentrations are presented as "ND", and a "<<" sign precedes the calculated emission rates and factors. All emission rates and factors corresponding to undetected concentrations are calculated based on the reported pollutant detection limit.

The emission factors and rates were determined using EPA recommended calculations. Emissions factors in lb/MMBtu were determined according to EPA Method 19 referenced in 40 CFR part 60, Appendix A. These factors are based on the measured pollutant concentration, fuel factor, and stack oxygen levels. Emission rates in lb/hr were determined using standard engineering calculations and are based on the measured pollutant concentration, exhaust stack flow rate, and the exhaust temperature. Emission factors in lb/HP-hr were based on the calculated emission rates (lb/hr), engine rating (HP), and load conditions. In cases where the fuel factor was not provided, EPA used the fuel factors provided in 40 CFR 60. It should be noted that the 40 CFR 60 fuel factors are within 3 percent of the average reported fuel factors for natural gas, and within 2 percent of the average reported fuel factors for diesel fuel.

Emissions factors were calculated according to Equations 1 through 5 below. For gaseous HAPs, Equations 1 and 2 were used to calculate emission rates in lb/hr and emission factors in lb/MMBtu, respectively. For particulate HAPs, Equations 3 and 4 were used to calculate emission rates in lb/hr and emission factors in lb/MMBtu, respectively. Equation 5 was used to calculate emission factors in lb/HP-hr for both gaseous and particulate HAPs. Load conditions are incorporated into Equation 5 to account for engine output power.

Equation 1: Emission Rate in (lb/hr) for gaseous HAPs:

$$ER\left(\frac{lb}{hr}\right) = \frac{1.369x10^{-9}\left(\frac{lb-mol^{o}R}{ft^{3}}\right) x\ 60\left(\frac{min}{hr}\right) x\ Q_{stk}\left(\frac{dscf}{min}\right) x\ C\ (ppb)\ x\ M\ \left(\frac{lb}{lb-mol}\right)}{(T_{std} + 460)^{o}R}$$

where: ER = Emission rate (lb/hr)

Q_{stk} = Stack gas flow rate (dscf/min)

C = Measured concentration (ppb)

M = HAP molecular weight (lb/lb-mol)

T_{stk} = Stack temperature (^{o}F)

Equation 2: Emission Factor in (lb/MMBtu) for gaseous HAPs:

$$EF_{F}\left(\frac{lb}{MMBtu}\right) = \frac{1.369x10^{-9}\left(\frac{lb-mol^{o}R}{ft^{3}}\right) x\ F_{F}\left(\frac{dscf}{MMBtu}\right) x\ C\ (ppb)\ x\ M\ \left(\frac{lb}{lb-mol}\right) x\ \frac{20.9}{20.9 - \%\ O_{2}}}{(T_{std} + 460)^{o}R}$$

where: EF_F = Emission factor (lb/MMBtu)

F_F = Fuel factor (dscf/MMBtu)

$\%O_2$ = Percent oxygen in the stack

Equation 3: Emission Rate in (lb/hr) for particulate HAPs:

$$ER\left(\frac{lb}{hr}\right) = 3.70x\ 10^{-9}\ C\left(\frac{\mu g}{dscm}\right) X\ Q_{stk}\left(\frac{dscf}{min}\right)$$

where: C = Measured concentration (g/dscm)

Equation 4: Emission Factor in (lb/MMBtu) for particulate HAPs:

$$EF_F\left(\frac{lb}{MMBtu}\right) = 6.23x\,10^{-11}\ X\ C\left(\frac{\mu g}{dscm}\right)\ X\ F_F\left(\frac{dscf}{MMBtu}\right)\ X\ \frac{20.9}{20.9 - \%\,O_2}$$

where: C = Measured concentration (g/dscm)

Equation 5: Emission Factor in (lb/HP-hr) for both gaseous and particulate HAPs:

$$EF_P\,(lb/HP - hr) = \frac{ER\,(lb/hr)}{P\,(HP)\ x\left(\frac{Load}{100}\right)}$$

where: EF_p = Emission factor based on power output (lb/HP-hr)
P = Power output (HP)
Load = Load conditions of the tested engine**.**

APPENDIX B

INDUSTRIAL COMBUSTION COORDINATED RULEMAKING

INFORMATION COLLECTION REQUEST

Stationary Reciprocating Internal Combustion (IC) Engines

This version of the Reciprocating IC Engine Questionnaire was prepared 1/6/97

Part I: General Facility Information

1. **Facility identification number from NEDS, if available:____**
   If the facility ID from NEDS is not available, provide a facility ID for use on this form:______________________

2. **Name of legal owner of facility:____**
   ____

3. **Name of legal operator of facility, if different from legal owner:____**
   ____

4. **Address of legal owner or operator:____**
   ____
   ____

5. **Size of company:**
   a. **Approximate number of employees of the business enterprise that owns this facility, including where applicable, the parent company and all subsidiaries, branches, and unrelated establishments owned by the parent company (answer may be given using the following ranges: 0-100; 101-250; 251-500; 501-750; 751-1,000; 1,001-1,500; or >1,500):**
   ____

   b. **Number of facility employees:____**

6. **Name of facility:____**

7. **Type of facility:**
   a. **Description of type of facility:____**
   b. **Standard Industrial Classification (SIC) Code:____**

8. **Size of facility:**
   a. **Total number of stationary reciprocating IC engines at the facility (50 bhp or greater):________________**
   b. **Total stationary horsepower (reciprocating IC engines 50 bhp or greater only):__________________bhp**

9. **Location of facility:**
   a. **Name of County (or Parish) where facility is located:____**
   b. **Complete street address of facility (physical location):____**
   c. **Complete mailing address of facility (if different from street address):_______________________________**

10. **Name and title of contact(s) able to answer technical questions about the completed survey:**

11. **Contact telephone number: (_____)_____________ Fax: (__)___________e-mail:___________________________**

PART II: Stationary Reciprocating Internal Combustion Engine Information

Please indicate the total number of stationary reciprocating internal combustion engines at the facility for each of the size classifications (per unit) included in the table below:

Rated Horsepower of Engine	Total Number of Stationary Engines at Facility	Number of Engines Listed in Previous Column that are Used for Emergency Standby Only
50-150		
151-300		
301-500		
501-750		
751-1000		
1001-1500		
1501-2000		
>2000		
Total Number of Engines		

For each engine included in the above table, please complete the Part III -- Engineering Information and Part IV -- Typical Operating Information forms, unless some units are identical. Identical units may be reported on the same Part III and Part IV forms. If identical units are reported on the Part III and Part IV forms, provide engine identification numbers for all units included on the same form. For the purposes of this survey, units may be considered identical only if all the following criteria are met:

a. All units have the same manufacturer and model number.
b. All engineering data for the units are the same.
c. All operating data for the units are the same.
d. The primary use of all the units is the same.

Photocopy this section in order to complete one Part IV -- Typical Operating Information form for each stationary reciprocating internal combustion engine listed in the table in Part II. Identical units may be reported on the same form.

Part III: Engineering Information

1. Identification number(s) assigned by the facility for reciprocating IC engines reported on this form, e.g., Engine 001:______________________________

2. Manufacturer Information:

   a. Engine Manufacturer:______________________________
   b. Engine Manufacturer's Model:______________________________

3. Year Installed:________________Has the combustion related hardware been changed since manufacture?
   G yes G no If so, when was the hardware changed:________________ Attach a brief description of what was done.

4. Engine Descriptors:
   a. Ignition: G Spark Ignition (SI) G Compression Ignition (CI), i.e., Diesel
      If SI, is the engine: G Rich Burn GLean Burn
   b. Stroke: G 2-stroke cycle G4-stroke cycle
   c. Primary fuel: G Liquid G Gaseous G Dual Fuel (pilot injection CI only)

5. Please provide the following information which typically is available from the engine nameplate (note that certain of these values may be different from the operating values):

   a. Bore:______________________________inches or mm (circle one)
   b. Stroke:______________________________ inches or mm (circle one)
   c. Displacement:________________cubic inches or liters (circle one)
   d. Rated Speed:________________ rpm
   e. Rated Power:________________bhp or kW (circle one)
   f. Compression Ratio:____________: 1
   g. Spark timing (SI):____________________ BTDC or injection timing (CI):______________ BTDC
   h. Manufacturer's Serial Number(s):______________________________

6. Engine Configuration:
   a. Cylinders: G In-line G Vee number of power cylinders:________________
   b. Engine aspiration (breathing):
      i. If 2-stroke cycle: G Blower Scavenged
         G Piston Scavenged
         G Pump Scavenged
      Is it also: G Turbocharged G Turbocharged with aftercooling/intercooling G Neither
      ii. If 4-stroke cycle: G Naturally Aspirated
         G Turbocharged/Supercharged
         G Turbocharged/Supercharged with aftercooling/intercooling

   c. If equipped with aftercooling/intercooling, what is the design cooling water temperature?
      G 85 F (29.5 C) G 130 F (54.5 C) G Other -- specify ________ F or C (circle one)

7. Primary engine use (please check one only):
   G Electric power generation (e.g., prime power or peak shaving)
   GCo-generation (electricity plus heat)
   G Steam or heat generation only
   G Mechanical power (e.g., pump, blower, compressor, etc.)
   G Transport of a liquid or gas (e.g., pipeline transmission)
   G Waste destruction (e.g., combustion of landfill or process byproduct gas)
   G Emergency only (electrical or mechanical -- circle one)
   G Other -- Please describe:____________________

Facility ID number:____________________ Company ID number(s) for reciprocating IC engine(s):______________________________

Photocopy this section in order to complete one Part IV -- Typical Operating Information form for each stationary reciprocating internal combustion engine listed in the table in Part II. Identical units may be reported on the same form.

Part IV: Typical Operating Information

Provide typical operating information on this form for each stationary reciprocating IC engine included in the Table in Part II. Please note that these values may be different from the rated or design data provided on the Part III -- Engineering Information form.

1. Hours of Operation (hr/yr): **Typical:_______________ Maximum:_________________**

2. Frequency of startups/shutdowns (no./yr): **Typical:_______________ Maximum:________________**
Hours during startups/shutdowns: **Typical:_________________ Maximum:________________**

3. Degree of automation: (check all that apply)
G manual G local automatic G remote automatic

4. Engine operating parameters (please note that certain of these values may be different from the rated values reported on the manufacturer's nameplate):

a. Operating Speed:___________________rpm

b. Operating Power:__________________ bhp or kW (circle one)

c. Spark timing (SI):__________________ BTDC or injection timing (CI):_____________ BTDC

d. Air to Fuel Ratio:___________________ by mass or by volume (circle one)

e. BMEP_____________________________psi or bar (circle one)

f. Peak Firing Pressure:_______________ psi or bar (circle one)

g. Average Heat Input:________________ MMBtu/hr LHV or HHV (circle one) at_________ bhp

h. Maximum Heat Input:______________ MMBtu/hr LHV or HHV (circle one) at _________ bhp

i. Steam generation:__________________ MMBtu/hr (co-generation units only)

6. Stack parameters: before or after control device (circle one):_____________________________________

a. Exhaust Gas Flow Rate:_____________ dscfm at _________________________________ bhp

b. Exhaust Temperature:______________ F at ___________________________________ bhp

c. Oxygen Concentration:______________% by vol. at ______________________________ bhp

7. Are emissions control device operated for this unit? G yes G no If so, please enter the control device identification number(s) assigned by the facility____________

8. Fuel used during normal operations (attach typical fuel analyses if available):

Fuel Use	**Fuel Code**	**LHV of HHV** Btu/SCF - Btu/gal (circle one)	**% NMHC** mass or vol. (circle one)	**Pretreatment**	**Analysis Provided**
Operating Fuel (1)	____________	______________	_________	**G yes* ______**	**G yes**
Operating Fuel (2)	____________	______________	_________	**G yes* ______**	**G yes**
Operating Fuel (3)	____________	______________	_________	**G yes* ______**	**G yes**
Startup Fuel	____________	______________	_________	**G yes* ______**	**G yes**
Standby Fuel	____________	______________	_________	**G yes* ______**	**Gyes**

Fuel Codes: **NG = Natural Gas LG = Landfill Gas GL = Gasoline RG = Refinery Gas**
DF = Diesel Fuel BF = Process Byproduct DG = Digester Gas
CO = Crude Oil MX = Mixture:____
OT = Other:____

*** Please provide the pretreatment code from the list below. If a pretreatment code is not listed for the device or method of pretreatment, please enter OT for "Other" and attach a brief description.**

Pretreatment Codes: (Work Group needs to provide these)

Photocopy this section in order to complete one Part IV -- Typical Operating Information form for each stationary reciprocating internal combustion engine listed in the table in Part II. Identical units may be reported on the same form.

Facility ID number:__________________ Company ID number(s) for reciprocating IC engine(s):_____________________________________

Photocopy this section in order to complete one Part V form for each emissions control device in service for the stationary reciprocating internal combustion engines listed in the table in Part II. Identical units may be reported on the same form.

Part V: Emissions Control Device Information

1. Control device identification number assigned by the facility, e.g., CD 001:__________________________

2. Does this control device control emissions from more than one IC engine? G yes G no
Identification number(s) for the reciprocating IC engine(s) served by this control device:_____________

____

3. Type of Emissions Control (check all that apply):

___ Air to Fuel Ratio ___ Catalytic Reduction ___ Retrofit Low Emission Combustion
___ Catalytic Oxidation ___ Ignition Timing ___ Pre-stratified charge
___ Miscellaneous Control Devices, describe:____

4. Manufacturer Information:
   a. Emissions Control Device Manufacturer:____
   b. Model:____

5. Year Installed:___________ Has permanent hardware been changed since manufacture? G yes G no
If so, when was the hardware changed:______________ Attach a brief description of what was done.

6. Control Efficiency:

Pollutant Controlled	Pre-Control Conc.* (ppm)	Post-Control Conc.* (ppm)	@15% O2	Other
___________________	__________________	___________________	__________	_________
___________________	__________________	___________________	__________	_________
___________________	__________________	___________________	__________	_________
___________________	__________________	___________________	__________	_________
___________________	__________________	___________________	__________	_________

* If the control device is low-emission combustion and the unit was purchased with the low emission combustion equipment, please provide only the post-control concentration.

7. Waste Streams Generated Due to Control Device Operation:

Waste Stream	Amount Per Year	Amount Disposed	Recycling Method
liquid wastewater	___________________	_______________________	___________________
liquid:___________	___________________	_______________________	___________________
solid:____________	___________________	_______________________	___________________
solid:____________	___________________	_______________________	___________________

8. Control Costs:
   a. Capital costs for emissions control device:________________________
   b. Annual costs for emissions control device:________________________
   c. Do you have detailed cost information? G yes G no If so, would you be willing to provide that cost information at a later time? G yes G no

ID number(s) for reciprocating IC engine(s) served by the control device:____

Photocopy this section in order to complete one Part V form for each emissions control device in service for the stationary reciprocating internal combustion engines listed in the table in Part II. Identical units may be reported on the same form.

Facility ID number:__ ID number for control device:________________________________

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Photocopy this section in order to complete one Part VI form for each reciprocating internal combustion engine for which emissions data is available.

Part VI: Emissions Information: Criteria Pollutants

NOTE: No New Testing is Required or Requested.

Report all limits included in current air permits in the **Permitted Emissions Limit** column in the table below. Report all **actual measured data** from air emissions tests in the **Measured Emissions** column in the table below. If no testing has been conducted for a pollutant listed in the table below, please draw a line through the pollutant name and mark an **"X"** in the **Measured Emissions** column. Do not report emissions based on emission factors provided by EPA, state or local agencies, or industry associations. If available, please submit a copy of the test report from which the data were obtained.

(If more than one device was vented through the stack on which measurements were made, please explain on a separate sheet.)

Pollutant	**Permitted Emissions Limit**[a]	**Measured Emissions**[b]	**Fuel Flow** (specify MCF or MMBtu/hr at LHV or HHV)	**Date(s) of Test(s)**	**O2 Level During Test (% dry)**	**Engine Load During Test (specify bhp or % rated bhp)**	**Test Method**[c]	**Number of Tests Included**[d]
CO	ppm[e] lb/hr g/bhp-hr	ppm[e] lb/hr g/bhp-hr						
NOx	ppm[e] lb/hr g/bhp-hr	ppm[e] lb/hr g/bhp-hr						
PM-10	ppm[e] lb/hr g/bhp-hr	ppm[e] lb/hr g/bhp-hr						
SO2	ppm[e] lb/hr g/bhp-hr	ppm[e] lb/hr g/bhp-hr						
VOC	ppm[e] lb/hr g/bhp-hr	ppm[e] lb/hr g/bhp-hr						

[a] Report all permitted emission limits that apply.

[b] Report any measured emission rates that are available. Do not report emissions information based on emission factors provided by EPA, or local agencies, or industry associations.

[c] Indicate the method 1) CEM; 2) Stack test, include test method, such as EPA Method 20, CARB Method 17; or 3) Other, include explanation.

[d] Provide the number of tests averaged to obtain the reported values.

[e] Pollutant concentrations reported as ppm should be reported as parts per million by volume on a dry basis, corrected to 15 percent oxygen content.

Facility ID number: ______________________________ Company ID number for reciprocating IC engine: ______________________________

Fuel ID for fuel inuse during testing: ________________

Photocopy this section in order to complete one Part VI form for each reciprocating internal combustion engine for which emissions data is available.

Part VI: Emissions Information: Hazardous Air Pollutants

NOTE: No New Testing is Required or Requested.

Report all limits included in current air permits in the **Permitted Emissions Limit** column in the table below. Report all **actual measured data** from air emissions tests in the **Measured Emissions** column in the table below. If testing was conducted for a pollutant listed in the table, but the pollutant was not detected, report **"ND"** for "not detected" in the **Measured Emissions** column. If no testing has been conducted for a pollutant listed in the table below, please draw a line through the pollutant name and mark an **"X"** in the **Measured Emissions** column. Do not report emissions based on emission factors provided by EPA, state or local agencies, or industry associations. If available, please submit a copy of the test report from which the data were obtained.

(If more than one device was vented through the stack on which measurements were made, please explain on a separate sheet.)

Pollutant	Permitted Emissions Limit[a]	Measured Emissions[b]	Fuel Flow (specify MCF or MMBtu/hr at LHV or HHV)	Date(s) of Test(s)	O2 Level During Test (% dry)	Engine Load During Test (specify bhp or % rated bhp)	Test Method[c]	Number of Tests Included[d]
Acetaldehyde	ppm[e] lb/hr g/bhp-hr	ppm[e] lb/hr g/bhp-hr						
Acrolein	ppm[e] lb/hr g/bhp-hr	ppm[e] lb/hr g/bhp-hr						
Benzene	ppm[e] lb/hr g/bhp-hr	ppm[e] lb/hr g/bhp-hr						
Dioxin	ppm[e] lb/hr g/bhp-hr	ppm[e] lb/hr g/bhp-hr						
Formaldehyde	ppm[e] lb/hr g/bhp-hr	ppm[e] lb/hr g/bhp-hr						

[a] Report all permitted emission limits that apply.

[b] Report any measured emission rates that are available. Do not report emissions information based on emission factors provided by EPA, or local agencies, or industry associations.

[c] Indicate the method 1) CEM; 2) Stack test, include test method used, such as EPA Method 0011, Method CARB 430; or 3) Other, include explanation.

[d] Provide the number of tests averaged to obtain the reported values.

[e]Pollutant concentrations reported as ppm should be reported as parts per million by volume on a dry basis, corrected to 15 percent oxygen content.

Facility ID number: ______________________________ Company ID number for reciprocating IC engine:____

Fuel ID for fuel inuse during testing: ________________

Photocopy this section in order to complete one Part VI form for each reciprocating internal combustion engine for which emissions data is available.

Part VI: Emissions Information: Hazardous Air Pollutants (continued)

NOTE: No New Testing is Required or Requested.

Report emissions for all other HAPs in the table below. A list of HAPs is provided as Attachment 1. Report all permit limits included in current air permits in the **Permitted Emissions Limit** column in the table below. Report all **actual measured data** from air emissions tests in the **Measured Emissions** column. If testing was conducted for a pollutant, but the pollutant was not detected, record the pollutant in the table below and report **ND** for "not detected" in the **Measured Emissions** column. Do not report emissions based on emission factors provided by EPA, state or local agencies, or industry associations. If available, please submit a copy of the test report from which the data were obtained.

(If more than one device was vented through the stack on which measurements were made, please explain on a separate sheet.)

Pollutant	Permitted Emissions Limit[a]	Measured Emissions[b]	Fuel Flow (specify MCF or MMBtu/hr at LHV or HHV)	Date(s) of Test(s)	O2 Level During Test (% dry)	Engine Load During Test (specify bhp or % rated bhp)	Test Method[c]	Number of Tests Included[d]
___________	ppm[e] lb/hr g/bhp-hr	ppm[e] lb/hr g/bhp-hr						
___________	ppm[e] lb/hr g/bhp-hr	ppm[e] lb/hr g/bhp-hr						
___________	ppm[e] lb/hr g/bhp-hr	ppm[e] lb/hr g/bhp-hr						
___________	ppm[e] lb/hr g/bhp-hr	ppm[e] lb/hr g/bhp-hr						
___________	ppm[e] lb/hr g/bhp-hr	ppm[e] lb/hr g/bhp-hr						

[a] Report all permitted emission limits that apply.

[b] Report any measured emission rates that are available. Do not report emissions information based on emission factors provided by EPA, or local agencies, or industry associations.

[c] Indicate the method 1) CEM; 2) Stack test, include test method used, such as EPA Method 0011, Method CARB 430; or 3) Other, include explanation.

[d] Provide the number of tests averaged to obtain the reported values.

[e] Pollutant concentrations reported as ppm should be reported as parts per million by volume on a dry basis, corrected to 15 percent oxygen content.

Facility ID number: ____________________________ Company ID number for reciprocating IC engine:____

Fuel ID for fuel inuse during testing: _______________

APPENDIX C

Testing & Monitoring WG's September 1997 recommendations on interpreting and using emissions databases containing non-detection values are available on the ICCR portion of the EPA TTN:

http://www.epa.gov/ttn/iccr/dirss/tmdetect.pdf

APPENDIX D

July 8,1997

FORMALDEHYDE MEASUREMENTS BY THE DNPH METHODS: A REVIEW BY THE TESTING AND MONITORING WORKGROUP

A. Validity of data in the EPA Database

Studies carried out by Radian International for the Gas Research Institute (GRI) have raised questions regarding the validity of aldehyde emission measurements using the CARB 430 procedure[11]. The industry uses CARB 430, EPA 0011, and related 2,4-dinitrophenyl hydrazine (DNPH) colorimetric procedures to measure formaldehyde emissions from combustion sources. Much of the aldehyde emission data that are available for EPA rule formulation were collected using DNPH procedures. The intent of this memorandum is to provide further guidance to the ICCR Source Groups on deciding which data are valid, and what test methods might be used for future measurements.

The Radian report shows evidence that the problem is related to NO_2 (not to be confused with NO or NOx) in the exhaust gas. DNPH reacts with all aldehydes to form derivatives which are then separated and analyzed by liquid chromatography. Radian has also found that DNPH also reacts with NO_2 to form a derivative. This side reaction with NO_2 can lead to depletion of the DNPH or produce other substances that mask the color that is produced by the aldehyde-DNPH reaction. In general, we recommend that Source Groups should be cautious in their use of CARB 430 data in the EPA data base.

The GRI reported only comparative measurement between the Fourier Transform Infrared (FTIR) analyzer and CARB 430 for natural gas fired internal combustion engines and found discrepancies between data from the two methods only with lean or clean burn engines. The GRI stated that they have "...no evidence of problems with their CARB 430 applications to natural gas-fired boilers, heaters, turbines or rich burn engines." Their data also showed that their CARB 430 data was always in agreement with the FT-IR results when the exhaust gas had less that 60 ppm of NO_2. Their data does not suggest that CARB 430 data should rejected on the basis of NO_2 interferences as long as the exhaust gas contains no more than 60 ppm NO_2 in the flue gas. The ICCR Source Groups may in fact be able to supply evidence that the exhaust gas from their sources do not exceed 60 ppm NO_2 thereby dispelling concerns about the validity of the CARB 430 data from their emission sources, or certain groups of their emission sources. The data should, of course, still be subjected to the usual engineering and statistical reviews before it is used in the rule making process.

[11] A September 11, 1996 letter to Ms. Amanda Agnew of the EPA from Mr. James M. McCarthy of the GRI regarding Internal Combustion Engine Test Methods.

During our review of the Radian study, it became evident that the Radian used formaldehyde concentrations found by FTIR to determine the sampling volumes used for the CARB 430 measurements in order to ensure that sufficient excess of DNPH would be present to react with formaldehyde. Since at that time they had not yet learned of the NO_2 interference, they inadvertently used too large a sampling volume. A closer review of CARB 430 indicates that the method does not specify volume of stack gas to be sampled. It is therefore possible that some of the data present in the EPA data base collected by CARB 430 may indeed be valid, even if the NO_2 levels were high. However, in the absence of specific information about NO_2 levels and sampling volumes for these tests, we believe that it is likely that these tests underestimate formaldehyde emissions from lean or clean burn engines.

B. Future Tests with DNPH Methods

The results of these field test show that formaldehyde emissions are likely to understated when determined by routine application of CARB 430 to lean or clean burn engines emitting high levels of NOx, in particular NO_2 . Operators of these type of sources should check their NO_2 emissions prior to doing any formaldehyde measurements to see if they have a potential problem. This can be accomplished using a portable NOx analyzer that provides NO and NO_2 data. The test contractor may than be able to adjust the sampling volume accordingly in order to avoid depletion of the DNPH by NO_2 .

Recent laboratory tested reported to GRI have succeeded in reproducing the step change decrease in formaldehyde concentrations when NO_2 concentration exceed 60 ppm. This was achieved by having the gas matrix containing formaldehyde and NO_2 more closely resemble that present in actual combustion gas emissions (i.e., including CH_4, CO, CO_2, NO, etc). This will permit the GRI to undertake laboratory experiments in the next few weeks that evaluate the Ashland and Celanese methods. Field studies evaluating these methods are planned in August-September 1997. The goal of these studies is to arrive at a cost effective method that will result in accurate measurements of formaldehyde emissions without necessarily having to employ the more expensive FTIR technique.

Our recommendation is that the DNPH procedures should not be rejected for future testing applications because of interferences that were observed with the lean and clean burn two-cycle internal combustion engines. Future testing is expected to result in an improved DNPH method which avoids interference present in emissions with high NO_2 levels. In addition, industry is also evaluating alternative procedures such as the Ashland method, a DNPH impregnated sorbent cartridge, and the Celanese method, an aqueous impingers techniques that measure total aldehydes.

Attachment 16

RICE Work Group Presentation on Above the Floor MACT Options for Landfill and Digester Gas

Item for Closure:

Above the Floor MACT for Digester and Landfill Gases

presented to:

ICCR Coordinating Committee

Durham, NC

presented by:

Greg Adams, Los Angeles County Sanitation Districts

on behalf of the RICE Work Group

September 16-17, 1998

Purpose

- To present EPA with guidance on Above the Floor technologies that should be considered for further evaluation for HAP emissions from RICE burning digester or landfill gas.

Background

- Digester and landfill gases are gaseous byproducts of the anaerobic decomposition of organic materials, principally comprised of:
  - methane
  - carbon dioxide
  - trace compounds, such as hydrogen sulfide, ammonia
- Among other pollutants, digester and landfill gas contain siloxanes which have been known to foul catalysts typically used for post combustion control of NO_x.
- WG determined that there is no MACT floor for landfill and digester gas fired engines.

Survey of Population (1 of 2)

- Conducted by Association of Metropolitan Sewerage Agencies (AMSA) in 1997 to identify RICE burning digester gas, and if any controls were in place to reduce HAPs.
  - 169 engines
    - 2 engines reported use of Selective Catalytic Reduction (SCR). However, as of August 1998, both SCR systems have been removed from operation due to catalyst fouling or high O&M costs for pretreatment of siloxanes.
    - 167 engines: some use Pre Combustion Chambers, Timing and Air to Fuel Ratio adjustments to reduce NO_x
  - No documentation of HAP reduction in this survey
  - AMSA data not yet incorporated into EPA database

Survey of Population (2 of 2)

- EPA Population Database identified 174 engines that burn landfill or digester gas
  - 3 digester gas engines had no controls
  - 171 landfill gas engines
    - » 10 rich burns use “air injection” for carbon monoxide (CO) control
    - » 1 lean burn with afterburner/flare for CO and Reactive Organic Compound (ROC) control

Above the Floor Control Technologies

- Three control technologies have been considered for above the floor MACT:
  - Catalytic Control
  - Air Injection
  - Lean Burn Engine with Flare-Afterburner

Above the Floor Control Technologies: Catalytic Control

- POTW's have a history of failed applications due to siloxanes fouling the catalysts.
- Pretreatment of landfill or digester gas to remove siloxanes is possible, but capital and operating costs are high.
  - No pretreatment/catalytic control systems are currently in operation in the U.S.
  - One pretreatment/SCR system was in place, but was replaced in 1998 with new lean burn engines due to high O&M costs.

Above the Floor Control Technologies: Air Injection

- Only used on rich burn engines running fuel-rich
- The ten systems in operation have had compliance problems with several Notices of Violation issued between January 1990 and May 1998
- Operator is planning to replace these units with lean burn engines
- WG members questioned the viability of this control technology for HAP reduction (as documented in the MACT Floor Rationale).

Above the Floor Control Technologies: Flare-Afterburner

- New system developed for NSPS combines a lean burn engine and flare-afterburner installed for the reduction of Non-Methane Organic Compounds (NMOC) for landfill emission control.
- Reactive Organic Compounds (ROC) BACT cost effectiveness analysis was performed, and proved cost effective for 25 tons/yr of ROC controlled. Cost effectiveness likely to be different due to lower amounts of HAPs.
- Since the system operates at 1500 degrees F, has the potential for HAP reduction.

Conclusion

- RICE WG does not believe that catalytic controls or air injection have proven reliable or cost effective enough to be considered for Above the Floor MACT
- RICE WG recommends that EPA further investigate HAP reduction performance and cost effectiveness of lean burn engine/afterburner flare control systems for landfill gas fired engines.

Attachment 17

Paper on Above the Floor MACT Options for Landfill and Digester Gas-Fired RICE (Closure Item)

WHITE PAPER

ABOVE THE FLOOR MACT
FOR
DIGESTER AND LANDFILL GAS

September 4, 1998

Purpose

The purpose of this document is to present EPA with guidance on the Above-the-Floor technologies that should be considered for further evaluation for controlling hazardous air pollutant (HAP) emissions from reciprocating internal combustion engines burning digester gas and/or landfill gas.

Background

Digester and landfill gases are gaseous by-products, principally comprised of methane and carbon dioxide, of anaerobic decomposition of organic materials. Trace quantities of other compounds are typically found in the gases including hydrogen sulfide and ammonia. In addition, a class of compounds called Siloxanes, which are silicon based compounds found in many cosmetics and cleaning solutions are also present in the gas. These compounds have been known to clog catalysts typically used for post-combustion control of Nitrogen Oxides (NOx).

These fuels are typically recovered by the facility operators and burned in combustion devices such as internal combustion engines to either generate electricity or directly power a pump or blower.

Survey of Population

A survey was conducted by the Association of Metropolitan Sewerage Agencies (AMSA), which represents the nations largest wastewater treatment agencies, in 1997 to identify what internal combustion engines were operating on digester gas and the type, if any, of controls that were installed to reduce HAP emissions. The results of the survey identified 169 engines (both lean and rich burn types) that burn digester gas. Of these 169 engines, two engines reported operating post-combustion control devices, specifically, Selective Catalytic Reduction (SCR). The other 167 engines reported no post-combustion control; however, many of these engines reported having combustion modifications for the control of NOx, including pre-combustion chamber, A/F ratio adjustment or timing adjustment. None of these combustion modifications have any documentation that demonstrates HAPs reductions. The results of this survey do not appear in the current EPA population database. However, AMSA has submitted their database in a format consistent with the EPA database, and EPA has indicated to AMSA that their data will be incorporated into EPA's database in the future.

The EPA population database developed by the Reciprocating Internal Combustion Engine (RICE) Workgroup identified 174 engines that burn either landfill gas or digester gas. Of the 174 engines, 3 burn digester gas. For all three digester gas engines, no controls for HAPs were in place.

Of the 171 engines identified in the EPA population database that burn landfill gas, a small percentage of the engines use an “air injection” emission control system on rich-burn engines. Apparently three landfills in California, operated by the same company, operate 10 rich-burn engines that utilize air injection to reduce Carbon Monoxide (CO) emissions. The Workgroup evaluated this emission control system and consider it inappropriate for reasons discussed in a later section of this White Paper. In addition, one landfill in Orange County has installed a new control technology system that combines a lean burn engine and afterburner flare that treats the exhaust of a lean burn engine. Since the flare operates at a temperature in excess of 1500 degrees Fahrenheit, there is the potential that this technology may reduce HAP emissions, and therefore should be further investigated.

As a result of the Workgroup’s review of existing technologies that have been applied on either digester gas or landfill gas engines, this White Paper will briefly summarize the applicability of three HAP control technologies to these fuels. These include catalytic control (NSCR or oxidation), air injection, and afterburner flaring.

Above-The-Floor Control Technologies

Catalytic Control

Publicly Owned Treatment Works (POTWs) have had a history of failed applications of catalytic control on digester gas fired engines. This includes both reductive and oxidative catalysts. The primary problem with catalyst is that a compound called Siloxane, which is silicon based and present in both digester and landfill gases, clogs the catalyst bed reducing the availability of sites where the catalytic reaction can occur, and ultimately renders the catalyst inoperable. It should be noted that installation of a pretreatment system to remove the Siloxane prior to combustion in the engine is possible, and will allow a catalytic control system to operate on digester and landfill gases. However, the cost to install and maintain such a system is substantial and is the reason why these pretreatment systems are not currently operating anywhere in the country. Case in point, a POTW in San Diego, which had installed an SCR system for NOx control on their engine, had installed a pretreatment system, which consisted of water drop out, physical screening and activated carbon, to remove the Siloxane prior to combustion in the engine. The system apparently worked, however, capital and operating costs were high and the facility decided to replace this system (in 1998) with a low- NOx lean burn engine.

Several case studies on the failure of catalytic controls on digester gas fired engines are briefly described below.

1. A report from Malcolm Pirnie (engineering consultant) to New York’s Nassau County Department of Public Works is attached. This report describes the reliability problems with oxidation catalysts applied to digester gas fired engines operating at two different

wastewater treatment plants. Based upon testing conducted in 1996, the engines catalyst's performance dropped to 80% efficiency after only 250 hours of operation and it became completely de-activated after approximately 700 hours of operation. The problem was identified as catalyst clogging due to Siloxane. The report also includes a discussion on several other applications of failed catalyst on engines and gas turbines burning digester gas.

2. A report by the City of Los Angeles' (CLA) Technology and Resource Recovery Division on testing of various oxidation catalysts in 1992 treating the exhaust stream of a gas turbine generator. The testing was conducted for the purpose of complying with a local air district rule for criteria pollutants and included an evaluation of seven different catalysts manufactured by five different companies. The study included evaluations of overall catalyst activity after 4,058 hours of service, evidence of physical masking, and evidence of catalyst poisoning. In the tests, the catalysts from two manufacturers failed, one catalyst manufacturer elected not to test the activity of their catalyst, and two catalyst manufacturers reported high catalyst activity after service (Kleenaire for a base metal on ceramic substrate and MetPro for both a base metal on ceramic substrate and precious metal on ceramic substrate). The CLA's conclusion was that a precious metal catalyst on a ceramic bed could work. However two precious metal catalysts on ceramic substrate were tested (Engelhard and MetPro) and one worked and the other failed. The factors that led to the one successful test are not clear. The CLA elected not to install the catalyst so there are no data available to show full scale successful application.

3. A 1984 report by the Los Angeles County Sanitation Districts (LACSD) on NSCR tests conducted on a digester gas fired engine. Conclusions from the test are that the catalyst did not operate reliably and could not meet the emission limits required by the local air district. The exact cause of the catalyst failure was not identified; however, silicon was detected in significant quantities on the catalyst bed.

4. A memorandum (with attached letters from catalysts manufacturers) from the LACSD summarizing catalyst manufacturers rejection to bid on supplying an SCR system for a turbine firing digester gas. Though the application was on a turbine, the important point with this memorandum is the catalyst manufacturers concern over detrimental effects on their catalysts due to contaminants in the digester gas.

Based upon AMSA member agency experience with catalysts, the fact that there are no catalyst controlled digester gas or landfill gas engines successfully operating in the United States, and that pretreatment systems to remove Siloxane are costly to install and maintain; the RICE Workgroup does not believe that catalytic control has proven reliable or cost-effective enough to be considered for above-the-floor MACT controls.

Air Injection for Rich-Burn Engines

There are ten (10) rich-burn, landfill gas fired engines utilizing an air injection emission control technology. These ten engines were originally equipped with NSCR to control NOx emissions. After early failure of the NSCR devices due to catalyst fouling, the operator attempted to meet emission requirements by modifying the operating parameters of the engines. This included running the engine at fuel-rich conditions. This resulted in lower NOx emissions, however, Carbon Monoxide (CO) emissions increased. Air injection into the exhaust stream was then added to control CO emissions.

The facility operator has received several notices of violation between January 1, 1990 and May 21, 1998 for the control systems. At one plant, seven NOx and two CO emission violations were received. At the second plant, five NOx and two CO emission violations were received. It is important to note that the facility operator has decided to replace these ten rich-burn engines with lean-burn engines.

Although the plants do not have actual emission data, there are several theoretical problems with this emission control system. Rich-burn engines operating fuel-rich produce more CO and formaldehyde emissions than engines operating at proper air-to-fuel ratios. The injection of air must be done precisely; if either too much or too little air is injected, both the rate of exhaust gas combustion and the resulting CO reduction efficiency will be affected. Proper mixing of the injected air is also important, since poor air distribution can cause sections of the exhaust gas stream to remain unburned.

Even if the control system is working perfectly, there is no evidence that is will reduce HAP emissions beyond that of a properly tuned engine. Therefore, the RICE Workgroup has determined that the use of fuel-rich/air injection for HAP emission control on rich-burn internal combustion engines is not appropriate.

Landfill Gas Flare-Afterburner

There is a landfill operating in Orange County (Prima Deschecha) that has installed a lean burn engine coupled with a flare-afterburner to meet the landfill gas, 98% destruction efficiency requirement of NSPS Subpart WWW. In addition, the Tajiguas landfill in Santa Barbara County has been issued a permit-to-construct (PTC) by the APCD to install a similar lean burn engine/flare-afterburner system. Based upon the PTC the flare-afterburner will operate in two modes. Its primary mode will be to treat the exhaust gas from the lean burn engine and directly burn a portion of the fugitive landfill gas that is collected and cannot be burned in the engine. The secondary mode of operation is to burn all of the fugitive landfill gas collected when the engine is not operating.

The NSPS Subpart WWW requires the control of Non-Methane Organic Compounds (NMOC). There is no requirement for HAP control. A NOx and Reactive Organic Compound (ROC) Best Available Control Technology (BACT) control cost effectiveness analysis was conducted for the Tajigues landfill PTC. This may have also been done for the Prima Deschecha landfill project; however, the RICE Workgroup did not have any documentation at the time of this White Paper. The economic analysis showed the project to be cost-effective for both NOx ($59/ton removed) and ROC ($1,589/ton removed) control. In the PTC's BACT cost-effectiveness analysis, the $1,589/ton of ROC removed is based on 25 tons/yr of ROC produced by the engine. The important consideration is that the economic evaluation may be different if it was based upon

HAP destruction since a new lean burn engine of this size (4,314 bhp) burning landfill gas would likely emit substantially less than 25 tons/yr of formaldehyde.

Since the afterburner-flare operates at a temperature in excess of 1500 degrees Fahrenheit, there is the potential that this technology may reduce HAP emissions. In addition, these systems are being installed to comply with NSPS Subpart WWW. Therefore, the RICE Workgroup believes that EPA should further investigate this technology for the control of landfill gas engines.

Conclusion

In summary, the RICE Workgroup does not believe that catalytic controls or air injection for rich-burn engines have proven reliable or cost-effective enough to be considered for above-the-floor MACT controls. We do recommend that EPA further investigate the HAP reduction performance and cost-effectiveness of the lean burn engine/flare-afterburner control system for landfill gas fired engines that is installed at the Prima Deschecha landfill in Orange County, California and soon to be installed at the Tajigues landfill in Santa Barbara County, California.

Supporting Documentation

The following documents that were referenced in this White Paper have been submitted into the NESHAPS RICE docket (A-95-35):

1. Malcolm Pirnie Consultants; Technical Memorandum, Catalyst Performance Investigation; prepared for the Nassau County Department of Public Works; September 1996

2. City of Los Angeles, Department of Public Works, Bureau of Engineering; Technical Report, CO and NOx Mitigation Catalyst Testing and Evaluation; December 1993

3. Los Angeles County Sanitation District; Catalytic Denitrification of Exhaust from Reciprocating Engines Fueled with Sewage Digester Gas; 77th Annual Meeting of the Air Pollution Control Association; June 1984

4. Los Angeles County Sanitation District; Memorandum; Responses to RFP for Correcting TEF/SCR System; July 1996

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Attachment 18

Presentation on Dioxin Primer Data/Information Item

DIOXIN PRIMER OVERVIEW

September 17, 1998

DIOXIN PRIMER OVERVIEW

Presented at 9/17/97 ICCR meeting by EPA/ORD and EER Corp. staff

Presentation covered:

- Chemistry and fundamental principles of dioxin/furan formation
- Factors influencing dioxin/furan formation in combustion units
- Control techniques
- Measurement and monitoring techniques

DIOXIN PRIMER OVERVIEW (Cont.)

At 9/17/97 meeting, CC developed the following recommendation to the Source WGs:

> "The CC requests that the WGs consider the content of the dioxin primer presentation in their deliberations; and when applicable, that consideration be given to GCP including P2, control device efficiencies, and surrogate pollutant levels in addition to existing data sets."

Action requested at todays meeting:

- CC to forward the dioxin primer to EPA as a data/information item for EPA consideration

Attachment 19

Presentation on RICE Work Group Works-In-Progress

RICE Works in Progress

presented to:

ICCR Coordinating Committee

Durham, NC

presented by:

Don Dowdall, Engine Manufacturers Association

on behalf of the RICE Work Group

September 16-17, 1998

RICE Works in Progress

- New Source MACT
- Pollution Prevention
- Definitions
- Catalyst Control Costs

New Source MACT

- Recommendations to EPA:
  - Use the same subcategories established for the MACT floor analysis
  - Identify the HAPs to be regulated based on the results of the RICE Testing Program
  - Consider the tradeoffs between individual HAPs and between HAPs and criteria emissions
  - Express the standard as a numerical emission limit for each engine subcategory and HAP.

Pollution Prevention (1 of 4)

- WG addressed the following topics:
  - Good Combustion Practices
  - Metrics
  - Operator Training
  - Fuel Constituent Standards

Pollution Prevention (2 of 4)

- Good Combustion Practices (GCPs)
  - No specific practices at this time for MACT floor
  - If GCPs are included, regulatory language should be general and limited to:
    - inspection/maintenance procedures in place
    - records to verify such procedures are followed
- Metrics
  - No metrics were identified to encourage P2 since engines are part of a process which must be considered as a whole for P2.

Pollution Prevention (3 of 4)

- Operator Training: No mandatory requirements are recommended by the WG.
  - » No evidence exists that there are quantifiable HAP reductions as a result of operator training.
  - » Significant practical difficulties would be encountered in implementing training or certification requirements.
    - existing population is highly heterogeneous
    - there are no known certification programs
    - some installations do not have an operator
    - current personnel do not have experience or training related to some topics beyond those specific to RICE.
    - training programs would be prohibitively expensive.

Pollution Prevention (4 of 4)

- Fuel Constituent Standards
  - Engines are designed to use a specific fuel, so there can rarely be any switching between fuels for a given engine.
  - Diesel and natural gas are the primary fuels used in RICE, and these fuels are already regulated.

Definitions

- Definitions of terms that may be used in the MACT standard were developed by the WG, and included:
  - a list of 23 definitions on which consensus was reached.
  - a list of 18 definitions on which consensus was not reached. Specific comments by WG members were included in this section.

Catalyst Control Costs

- Gathered control cost information on NSCR and CO catalysts from 4 catalyst vendors based on $/HP.
- WG determined that the $/HP costs are insufficient for conducting a cost effectiveness analysis
- WG developed a detailed cost request letter was sent to vendors which included:
  - a list of specific engines on which to quote prices
  - a description of the OAQPS cost manual methodology.

Recommendation to CC

- The RICE WG recommends that the CC forward these materials as Works in Progress of the RICE WG to EPA.

Attachment 20

Environmental Caucus Environmental Justice Proposal (Work-In-Progress) and Background Materials

Industrial Combustion Coordinated Rulemaking
Environmental Caucus Proposal For Regulatory Action

Topic Permitting/Environmental Justice

Proposal There is a simple, inexpensive addition to the administration of the permitting process for ICCR sources that would address important environmental justice concerns without imposing a burden on any operator or permitting entity, and which would not affect or displace local land use processes. The proposal is:

The following information shall be assembled and made publicly available as part of the review of a Title V permit application by an ICCR source:

1. **the racial and economic characteristics (measured as the percentage of the population within the low income category) of people living in the census track in which the facility will operate and the immediately adjoining census tracks, by comparison to the racial and economic characteristics of people living in the state and the standard metropolitan statistical area (SMSA) or county, using the most recently available census data;**

2. **for the census track and adjoining census tracks, a listing and description of the facilities which already possess or are seeking permits pursuant to any federal law administered by the U.S. Environmental Protection Agency and/or by a State program to which the USEPA has delegated its permitting and/or enforcement authority; and,**

3. **a description of the volume per year for each pollutant the facility will be permitted to release and a description of the Overall PBT Chemical Score for each pollutant as established on the Prioritized Chemical List (EPA Docket F-97MPCA-5F).**

Discussion This proposal is designed to be easily administered, using information sources which are already compiled for other purposes. This proposal is also designed to provide critical information relevant to concerns broader than technical compliance with permit requirements. The compilation and disclosure of this information will enhance the potential for collaborative decision-making among regulatory agencies, the regulated entity and individuals most directly affected by regulated activities. Dissemination of this information during the permitting process offers an opportunity for thoughtful consideration of these issues at the appropriate time, defusing tensions inherent in facility permitting decisions.

BACKGROUND INFORMATION: THE ICCR ENVIRONMENTAL CAUCUS ENVIRONMENTAL JUSTICE PROPOSAL

> The Environmental Caucus EJ proposal is an **information-only** proposal.

> The Caucus EJ proposal **does not provide a new basis for federal intervention into local or state land use decision making processes.**

> This EJ proposal is designed **to assist regulators, regulated entities and the public to understand and address EJ-related issues proactively at the time of permitting**. This is an alternative to the present system, in which the only remedies to address EJ concerns are after-the-fact judicial and administrative complaints. By front loading EJ information into the permitting process, it will allow regulators, regulated entities and the public to address EJ concerns, if any, at the permitting stage.

> The Environmental Caucus shares the general concern about the difficulty of accurately characterizing the toxicity of different compounds, as recommended in paragraph 3 of the EJ proposal. Clearly, no one benefits if these risks are either exaggerated or minimized. However, the Caucus stresses **the goal of accurately characterizing the relative risks of different air pollutants is worthwhile even if the Caucus' specific proposal is not the means to accomplish this purpose.**

> The EJ proposal is flexible in that **it does not dictate how its requirements will be implemented**. Instead, the proposal merely adds some new, readily available categories of information into existing permitting processes for ICCR sources. The proposal **entails little if any additional expense for any entity**, and **will not create delay** in the process of implementing regulations through facility-by-facility permitting.

> The EJ proposal may or may not be broadly applicable; however, **it is proposed at this time for one specific rulemaking process**. This is not an attempt to single out ICCR sources for special scrutiny. Rather, it is a modest proposal to enable rulemaking for ICCR sources to conform with U.S. EPA's obligations under Executive Order and established agency policy. Indeed, the Environmental Caucus would be doing a disservice to ICCR if it did not develop an appropriately scaled EJ proposal for inclusion in this rulemaking.

> The EJ proposal **is designed to be consistent with U.S. EPA's Interim Guidance** on Environmental Justice and Title VI. This is reflected in the new categories of information that the Caucus proposal identifies for inclusion in the permitting of ICCR sources.

> The EJ proposal **was circulated to environmental activists** prior to submission to ICCR. The EJ proposal **is designed to address the concerns raised by ICCR participants** following the Caucus presentation on environmental justice.

Background Information Presented at Previous CC Meeting in September 1997

Environmental Justice

The Agency Definition of Environmental Justice

According to U.S. EPA, environmental justice means:

* the fair treatment of people of all races, cultures and incomes with respect to the development, implementation and enforcement of environmental laws, regulations, programs and policies;

* that no racial, ethnic or socioeconomic group should bear a disproportionate share of the negative environmental consequences resulting from the operation of industrial, municipal and commercial enterprises and from the execution of federal, state and local programs and policies; and,

* that communities, private industries, local governments, states, tribes, federal government, grass roots organizations and individuals act responsibly and ensure environmental protection to all communities. See 58 Fed. Reg. 63955, 63957 (December 3, 1993).

Why is environmental justice relevant to ICCR?

Environmental justice is relevant to all U.S. EPA activities by virtue of Executive Order and well-established Agency policy. In addition, there are specific mandates in the Clean Air Act, including provisions of Section 129 now before the ICCR, which are relevant to environmental justice issues. To the extent U.S. EPA will delegate its responsibilities for implementation and enforcement of combustion emission standards to its State partners, it is authorized to impose and enforce requirements to ensure non-discrimination. Finally, it is anticipated the Agency will issue definitive guidance on the legal requirements arising from its commitment to environmental justice in the near future.

Executive Order 12898

President Clinton signed Executive Order No. 12898, Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations, on February 11, 1994. 59 Fed. Reg. 7629 (Feb. 16, 1994).

Executive Order No. 12898 does not create a new legal remedy. Reno, Janet. "Department of Justice Guidance Concerning Environmental Justice" (January 9, 1995), p. 2. As an internal management tool of the Executive Branch, the Order directs Federal agencies to put into place procedures and take actions to make achieving environmental justice part of their basic mission. Id. President Clinton explained that Federal agencies have the responsibility to promote "nondiscrimination in Federal programs substantially affecting human health and the environment." Id. Accordingly, agencies must implement actions to identify and address disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority and low-income populations and federally-recognized Indian tribes. Id.

In a memorandum issued contemporaneously with the Order, the President "underscored certain provisions of existing law that can help ensure that all communities and persons across the Nation live in a safe and healthful environment". Id. For example, the Presidential memorandum emphasizes that Title VI of the Civil Rights Act of 1964 provides an opportunity for Federal agencies to address environmental hazards in minority communities and low-income communities. This purpose is accomplished by ensuring compliance with the existing non-discrimination provisions in Federal contracts with State agency partners.

U.S. EPA Policy

U.S. EPA has two overarching goals in relationship to environmental justice. U.S. Environmental Protection Agency, Draft Environmental Justice Strategy for Executive Order 12898 (January, 1995). U.S. EPA's first goal is to ensure that no segment of the population, regardless of race, color, national origin, or income, suffers disproportionately from adverse human health or environmental effects as a result of EPA's policies, programs, and activities Id. "Introduction" by Carol M. Browner.

U.S. EPA's second overarching goal is to ensure that those who must live with environmental decisions - community residents, environmental groups, State, Tribal and local governments, businesses - must have every opportunity for public participation in the making of those decisions. Id. An informed and involved local community is regarded as a necessary and integral part of the process to protect the environment. Id.

The connections between the Clean Air Act and environmental justice were first described U.S. EPA during the Bush Administration in a report entitled Environmental Equity - Reducing Risk For All Communities, EPA230-R-92-008, June 1992. Among the primary factual conclusions of this report is that racial minorities, who live in urban areas in higher percentages than their white counterparts, disproportionately experience the consequences of higher air pollution found in urban settings.
The Environmental Equity report concludes:

> *The literature available suggests that exposure, siting, sensitivity, and the distribution of air pollutants raise concerns about equity with respect to air pollution. Available studies do not demonstrate (or even raise the suggestion) that OAR's policies have resulted in differential allocations of environmental benefits. However, the literature examined suggests that racial minority and low-income populations have experienced poorer air quality because they tend to live in urban areas and have in some cases lived in close proximity to air polluting facilities. Also, in some cases, they may be more sensitive to certain air pollutants than the general population.*

In considering this conclusion in light of OAR's opportunities under the 1990 Clean Air Act Amendments, the report observes:

> *To the extent urban air quality is improved via the Act, minority populations will experience higher relative benefits than the general population because of their high representation in urban areas.*

In discussing the effects of regulatory action mandated under the 1990 amendments, the report concludes:

The reductions in exposure and associated control costs will in general be distributed widely. However, several of the changes enacted could potentially have greater economic impacts on low-income people than on middle-or high-income groups...Once again, opportunities exist for EPA to include consideration of those racial minority and low-income communities who are at greatest risk than the population as a whole in development of this guidance.

Clean Air Act/Section 129

The focus of the Air Division's environmental justice opportunities is in rule development under the Clean Air Act of 1990. These opportunities include considering environmental justice in NSR and PSD permitting, improving public participation under Title V, establishing siting standards for incinerators under Section 129, revising ambient air quality standards, and incorporating environmental justice into research and regulation of hazardous air pollutants.

There are three opportunities which are specifically important for ICCR. First, Section 129 (a)(3) requires siting requirements for new solid waste burning units which "minimize, on a site specific basis, to the maximum extent practicable, potential risks to public health or the environment." ICCR provides a clear opportunity for rulemaking on this requirement, including the identification of factors and procedures (including enhanced public participation) which must be used in the characterization of risk minimization.

Second, there are opportunities under Sections 112, 129 and 501 to enhance public participation in the permitting of combustors. These opportunities are separately described in a background paper entitled Legal Aspects of Public Participation.

Third, because U.S. EPA is authorized to, and anticipates, delegating implementation of combustor rules to States (see 112(l), and, 129(b)(2)), rules developed through ICCR could include terms designed to address disproportionate impact and public participation in subsequent state activities. The Administrator could also independently include these terms in delegation agreements.

Title VI

Pursuant to Title VI of the Civil Rights Act of 1964, U.S. EPA must ensure that programs or activities receiving EPA financial assistance that affect human health or the environment do not directly, or through contractual or other arrangements, use criteria, methods, or practices that have a discriminatory effect on the basis of race, color or national origin. Memorandum from Jean C. Nelson, General Counsel, to Carol Browner, Administrator, March 17, 1994. As a practical matter, this requires U.S. EPA to enforce a standard provision in its grant agreements with its State-funded partners, in which States agree they -

> *6. Will comply with all Federal statutes relating to non-discrimination. These include but are not limited to: (a) Title VI of the Civil Rights Act of 1964 (P.L. 88-352)...*

ICCR does not have a mandate related to Title VI. However, two provisions which are directly relevant to ICCR provide a basis for further defining how States can conduct their federally-funded, federally-delegated activities so as to avoid violating non-discrimination requirements.

Section 112(l) indicates that States may develop and submit programs for the implementation and enforcement of standards established pursuant to Section 112. For her part, the Administrator is required to publish guidance which establishes the criteria through which States can develop and seek approval for these programs. It may be possible for the Administrator to establish environmental justice requirements under Section 112 as part of the delegation of this program to States. We should consider inquiring about the willingness of the Administrator to use this authority to promulgate requirements which will ensure States are exercising their authority consistently with Title VI.

Section 129(b)(2) indicates that States in which solid waste burning facilities are operating shall submit to the Administrator a plan to implement and enforce Section 129 guidelines. The Administrator is given broad discretion over the approval or disapproval of these mandatory State plans. Moreover, the standards for approval for new sources must include factors unique to Section 129(a)(3): a determination of methods and technologies for removal or destruction of pollutants before, during and after combustion; and, siting requirements that minimize "to the maximum extent practicable" potential risks to human health and the environment. These unique requirements suggest the Administrator should incorporate guidance on Title VI into the review and approval of state plans to implement and enforce 129(a)(3).